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December 3, 2013

Mr. John Kistle
AES North American Development, LLC
690 N. Studebaker Road
Long Beach, CA 90803

Re: Huntington Beach Project
Q #: 893 – CAISO Cluster 5 Phase II Interconnection Study

Dear Mr. Kistle:

Attached is the Cluster 5 Phase II Interconnection Study Report for the interconnection of the proposed Huntington Beach Energy Project to the CAISO Controlled Grid. The CAISO and SCE performed the Phase II Interconnection Study in accordance with the CAISO's Generator Interconnection and Deliverability Allocation Procedures (GIDAP) tariff.

Please review the report and prepare comments and questions for the Results Meeting. The Phase II Interconnection Study Results Meeting will be coordinated and scheduled within 30 calendar days following receipt of this Phase II Interconnection Study report.

Sincerely,

Robert Sparks
Manager, Regional Transmission – South

Attachment(s)

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Queue QC5 Phase II Interconnection Study Report

SCE Metro Area Report

Final Report

December 3, 2013

This study has been completed in coordination with Southern California Edison per CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

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A. Introduction

In accordance with the California Independent System Operator (CAISO) Generator Interconnection and Deliverability Allocation Procedures (GIDAP) Tariff Appendix DD, this Queue QC5 Phase II Study was performed to determine the combined impact of all the QC5 Phase II projects on the CAISO Controlled Grid.

There were 19 QC5 Phase II generation projects in the SCE's service territory modeled in the Phase II Study. The 19 generation projects comprise two (2) previously queued Energy Only projects requesting Full Capacity Deliverability Status and the remaining seventeen (17) are new interconnection requests. Five (5) general study areas were formed based on the electrical impact among the generation projects: Northern Area, Eastern Bulk Area, East of Pisgah Bulk Area (EOP), North of Lugo Bulk Area (NOL), and Metro Area. This Metro Area study report provides the following:

- Transmission system impacts caused by the addition of QC5 Phase II projects requesting interconnection in the SCE Metro Area,
- System reinforcements necessary to mitigate the adverse impacts under various system conditions of the QC5 Phase II projects requesting interconnection in the SCE Metro Area,
- A list of required facilities and maximum cost responsibility for Reliability Network Upgrades (RNUs) and Local Delivery Network Upgrades (LDNUs) assigned to each Interconnection Request
- A cost estimate of Area Delivery Network Upgrades (ADNUs) for each Interconnection Request that has selected Option (B)
- A good faith estimate of the Interconnection Facilities cost
- A good faith estimate of time to construct the Network Upgrades and Interconnection Facilities for each Interconnection Request.

To determine the system impacts caused by QC5 Phase II projects, the following studies were performed:

- Steady State Power Flow Analyses
- Short Circuit Duty Analyses
- Transient Stability Analyses
- Reactive Power Deficiency Analyses
- Deliverability Assessment
- In-Service Date and Commercial Operation Date Assessment

A.1 QC5 Phase II Generation Project Interconnection Information

A total of two (2) generation projects made up the QC5 Metro Area.

There are two (2) generation projects totaling a maximum output of 1414.332 MW included in QC5 in the Metro Area. Table A.1 lists all the new generator projects in the Metro Area Bulk System with essential data obtained from the CAISO Generation Queue.

Table A.1: SCE QC5 Projects (Metro)

CAISO Queue	Point of Interconnection	Full Capacity Energy Only	Fuel	Max MW	Proposed COD (as filed with IR)
893	Huntington Beach 220 kV Substation	FC	CC	938.612	6/01/2020
941	Redondo Beach 220 kV Substation	FC	CC	475.72	12/31/2018
Total QC5 Generation (Metro System)				**1414.332**	

A.2 Study Objectives

This QC5 Phase II Interconnection study was performed in accordance with Section 8.1 of Appendix DD of the CAISO Tariff, which states:

The Phase II Interconnection Study shall:

(i) update, as necessary, analyses performed in the Phase I Interconnection Studies to account for the withdrawal of Interconnection Requests from the current Queue Cluster;

(ii) identify final RNUs needed to physically and reliably interconnect the Generating Facilities and provide final cost estimates;

(iii) identify final LDNUs needed to interconnect those Generating Facilities selecting Full Capacity or Partial Capacity Deliverability Status and provide final cost estimates,

(iv) identify final ADNUs for Interconnection Customers selecting Option (B), as provided below and provide revised cost estimates;

(v) identify, for each Interconnection Request, the Participating TO's Interconnection Facilities for the final Point of Interconnection and provide a +/-20% cost estimate; and

(vi) coordinate in-service timing requirements based on operational studies in order to facilitate achievement of the Commercial Operation Dates of the Generating Facilities.

In order to achieve the above objectives, this same Section 8.1 explains what specific studies need to be done:

The Phase II Interconnection Study report shall set forth the applicable cost estimates for RNUs, LDNUs, ADNUs and Participating TOs Interconnection Facilities that shall be the basis for Interconnection Financial Security Postings under Section 11.2 and 11.3 Where the cost estimations applicable to the total of RNUs and LDNUs are based upon the Phase I Interconnection Study (because the cost estimation for the subtotal of RNUs and LDNUs were lower and so establish maximum cost responsibility under Section 10.1), the Phase II Interconnection Study report shall recite this fact.

The Phase II Study analysis was performed to identify the conceptual Interconnection Facilities, Plan of Service Reliability Network Upgrades, Reliability Network Upgrades, Local Delivery Network Upgrades, incremental Area Delivery Network Upgrades, and Distribution Upgrades necessary to safely and reliably interconnect the QC5 Phase II projects. An estimated cost and construction schedule for these facilities is provided in this report.

B. Study Assumptions

B.1 Load and Intertie Flows Assumptions

The 2016 summer peak reliability cases modeled 25,286 MW load (1-in-10 load forecast). The 2016 summer off peak reliability cases modeled 15,285 MW, approximately 60% of summer peak load. .

The Deliverability Assessment On-Peak case modeled a 24,862 MW load (1-in-5 load forecast) in the SCE system with an import target as shown in Table B-1 of Appendix B. The Off-Peak case modeled a 16,364 MW load in the SCE system.

While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, the base cases were developed to represent stressed scenarios of loading and generation conditions for the study group area.

B.2 Generation Dispatch Assumptions

Generation assumptions for SCE's Metro Area are shown in the tables[1] provided in Appendix B.

Generation dispatch assumptions in Deliverability Assessment can be found at http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf. In the on-peak Deliverability Assessment, the Summer Peak Qualified Capacity (QC) for proposed Full Capacity generation projects is set to 64% of the requested PMax for wind generation and 100% of the requested PMax for solar generation initially. The Summer Peak QC may be adjusted to 40% of the requested PMax for wind generation and 85% for solar generation if a mix of different fuel type generations is identified in the Deliverability Assessment as the 5% Circle for a transmission limitation. In the off-peak Deliverability Assessment, the proposed Full Capacity wind generation is dispatched at its maximum nameplate output and solar generation at 85% of its nameplate output.

[1] These tables reflect the latest project information at the time the study was performed and may not reflect the numerous changes to the queue (i.e. withdraws, project size reductions, etc.) that have taken place during the course of the study.

B.3 Transmission System Assumptions

The QC5 Phase II Study included the modeling of all CAISO-approved transmission projects in the Metro System base cases. In addition, a number of transmission upgrades are needed to support queued ahead serial generation projects in the Metro System were modeled in order to determine if additional facilities would be needed to support the Phase II projects.

B.3.1 Previously Triggered Area SPS

The interconnection of a higher queued project required the implementation of a SPS to protect for thermal overload on the El Nido-La Cienega 220 kV line for the N-2 outage of the El Nido-La Fresa 3 & 4 220 kV lines

B.4 Special Protection Systems and Operating Procedures

Existing System Operating Bulletins (SOB), Operating Procedures (OP), and Special Protection Systems (SPS) may be relevant for QC5 Study analysis in the SCE Metro System. These include, but are not limited to, the following:

- SOB-013 (Critical System Voltage)
- SOB-017 (System Voltage Control)
- SOB-292 (Santiago N-2 Remedial Action Scheme)
- SOB-293 (El Nido N-2 Remedial Action Scheme)

B.4.1 Operating Procedures

Operating procedures, which may include curtailing the output of the QC5 Phase II projects during planned or extended forced outages, may be required for reliable operation of the transmission system. These procedures, if needed, will be developed before the projects' Commercial Operation Date.

B.5 Queued Ahead Triggered Circuit Breaker Upgrades, Replacement or Mitigation Requirements

This QC5 Phase II Study evaluated both the pre-QC5 and post-QC5 conditions to properly identify all queue-ahead triggered short-circuit duty mitigations and properly assign mitigation for those impacts that are triggered by the addition of QC5. It is important to recognize that previous studies may have identified mitigation requirements which are now different due to the number of project withdrawals that have occurred since the queued-ahead studies were completed. As a result, it is possible that the mitigation previously defined in a queued ahead project's study is now assigned to projects as part of this QC5 Phase II Study. Section H provides both a list of previously triggered short-circuit duty mitigations based on most current interconnection queue as well as short-circuit duty mitigations triggered with the addition of the projects that are part of this QC5 Phase II Study.

B.6 Pre-QC5 Affected System Transmission Upgrades

No transmission upgrades outside the CAISO controlled grid were identified as in the previous generation interconnection studies for the SCE Metro system. However, neighboring utilities may identify need for physical upgrades within their system not identified in the studies.

B.7 Power Flow Base Cases

The QC5 Phase II Study power flow cases were developed from the WECC base case and PTO's transmission expansion base case series representing summer peak and s summer off peak load conditions. The QC5 Phase II studies were based on a 2016 load forecast. These power flow cases included all CAISO approved transmission projects, as well as earlier queued Serial Group and cluster generation projects with associated Network Upgrades and Special Protection Systems.

B.7.1 2016 Base Cases

The following power flow cases were used for the analysis in the SCE Metro Area QC5 Phase II Study:

2016 Summer Peak Full Loop Power Flow Case:

Power flow analyses were performed using SCE's peak full loop base case (in General Electric Power Flow format). This base case was developed from base cases that were used in the SCE annual transmission expansion plan studies. It has a 1-in-10 year adverse weather load level for the SCE service territory.

2016 Summer Off Peak Full Loop Power Flow Case:

Power flow analyses were also performed using the off-peak full loop base case in order to evaluate system performance due to the addition of Phase II generation projects during light load conditions. The off-peak load was modeled at about 60% of the peak load level.

The power flow cases modeled all CAISO approved transmission projects, regardless of their proposed in-service date. The power flow cases also modeled all Pre-QC5 generation projects regardless of their proposed COD. These generation projects were modeled along with their identified transmission upgrades necessary for their interconnection and/or delivery.

B.8 Deliverability Base Cases

B.8.1 Master Deliverability Assessment Base Case

A master base case was developed for the QC5 on-peak deliverability assessment which modeled all the Pre-QC5 and QC5 Phase II generation projects. The resources in the master base case are dispatched as follows:

- Existing capacity resources are dispatched at 80% of their summer peak Net Qualified Capacity (NQC).
- Proposed full capacity resources are dispatched to balance load and maintain expected imports, but not exceeding 80% of their summer peak NQC.
- Energy-Only (EO) resources are considered off-line.
- Imports are at the maximum summer peak simultaneous historical level by branch group as shown in Table B-1 in Appendix B.
- Non-pump load is at the 1-in-5 peak load level for CAISO.
- Pump load is dispatched within expected range for summer peak load hours.

B.8.2 SCE Metro Area Deliverability Assessment Base Case

The SCE Metro Area deliverability assessment base case was developed from the master base case by dispatching all proposed full capacity resources in the Metro Area to 80% of their NQC.

C. Reliability Standards, Criteria and Methodology

C.1 Reliability Standards and Criteria

The generator interconnection studies were conducted to ensure the CAISO Controlled Grid is in compliance with the North American Electric Reliability Corporation (NERC) reliability standards, WECC regional criteria, and the CAISO planning standards.

C.1.1 NERC Reliability Standards

The CAISO analyzed the need for transmission upgrades and additions in accordance with NERC reliability standards. These standards set forth criteria for system performance requirements that must be met under specific set of operating conditions. The following NERC reliability standards are applicable to the CAISO, as a registered NERC Planning Authority, and the PTOs, as Transmission Planners, and are the primary standards for the interconnection of new facilities and system performance[2]:

- FAC-001: Facility Connection Requirements[3]
- FAC-002: Coordination of Plans for New Facilities
- TPL-001: System Performance Under Normal Conditions (category A);
- TPL-002: System Performance Following Loss of a Single Bulk Electric System (BES) Element (category B)
- TPL-003: System Performance Following Loss of Two or More BES Elements (category C).

C.1.2 WECC Regional Criteria

The WECC TPL system performance criteria are applicable to the CAISO as a Planning Authority and set forth additional requirements that must be met under a varied but specific set of operating conditions.[4]

C.1.3 California ISO Planning Standards

The California ISO Planning Standards specify the grid planning criteria to be used in the planning of CAISO transmission facilities.[5] These standards cover the following:

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[2] http://www.nerc.com/page.php?cid=2%7C20

[3] http://www.nerc.com/files/FAC-001-1.pdf; FAC-001 is applicable to PTOs, but not to the ISO

[4] http://compliance.wecc.biz/application/ContentPageView.aspx?ContentId=71

[5] http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf

- Address specifics not covered in the NERC reliability standards and WECC regional criteria;
- Provide interpretations of the NERC reliability standards and WECC regional criteria specific to the CAISO Controlled Grid; and
- Identify whether specific criteria should be adopted that are more stringent than the NERC standards or WECC regional criteria.

C.1.4 Contingencies

The system performance with the addition of the generation projects were evaluated under normal conditions and following loss of single or multiple BES elements as defined by the applicable reliability standards and criteria. Table C-1 summarizes the contingencies per NERC Reliability Standards, WECC Regional Criteria and CAISO Planning Standards.

Table C-1: Contingencies

Contingencies	Description
NERC TPL-001 NERC Category A (No contingency)	All facilities in service – Normal Conditions
NERC TPL-002 Category B	B1 – SLG or 3Φ Fault, with Normal Clearing: single generator outage B2 – SLG or 3Φ Fault, with Normal Clearing: single transmission circuit outage B3 – SLG or 3Φ Fault, with Normal Clearing: single transformer outage B4 – Single Pole Block, with Normal Clearing: single pole (dc) line outage
CAISO Planning Standard Category B	II.2. – Selected overlapping single generator and transmission circuit outages II.5. – Loss of combined cycle power plant module
NERC TPL-003 Category C	C1 – SLG Fault, with Normal Clearing: Bus outages C2 – SLG Fault, with Normal Clearing: Breaker failures C3 – SLG or 3Φ Fault, Combination of any two-generator/transmission line/transformer outages except these in CAISO Category B C4 – Bipolar Block, with Normal Clearing: Bipolar (dc) Line C5 – Outages of double circuit tower lines C6 – SLG Fault, with Delayed Clearing: Generator C7 – SLG Fault, with Delayed Clearing: Transformer C8 – SLG Fault, with Delayed Clearing: Transmission Circuit C9 – SLG Fault, with Delayed Clearing: Bus Section
WECC Business Practice TPL-001-WECC-RBP-2 Category C	WR1.1 – SLG Fault, with Normal Clearing: two adjacent transmission circuits (greater than 300 kV) on separate towers

In the Phase II Study, all NERC Category B, WECC WR1.1, as well as the worst Category C1 through C9 outages, in the electrical vicinity of the general study area were analyzed. The worst Category C contingencies were selected by taking into account the following factors:

- Amount of generation lost immediately following the outage

- Normal condition loading of a transmission facility
- Bus outages and breaker failures that cause disconnection of the entire bus during the transient period

Category C3 outages were limited to double contingencies that resulted in loss of generation greater than half the amount required for the largest double contingency in the SCE service territory.

C.2 Steady State Study Criteria

C.2.1 Normal Overloads

Normal overloads are those that exceed 100 percent of normal facility rating under NERC Category A conditions (no contingency). Normal overloads are identified in Deliverability Assessment and Reliability Study power flow analyses in accordance with the Reliability Standard TPL-001. It is required that loading of all transmission system facilities be within their normal ratings under NERC Category A conditions.

C.2.2 Emergency Overloads

Emergency overloads are those that exceed 100 percent of emergency ratings under NERC/WECC/ CAISO Category B and Category C contingency conditions. Emergency overloads are identified in the Deliverability Assessment and Reliability Study power flow analyses in accordance with Reliability Standards TPL-002 and TPL-003. It is required that loading of all transmission system facilities be within their emergency ratings under the Category B and Category C contingency conditions.

C.2.3 Voltage Criteria

A voltage criteria violation occurs if a bus within the CAISO Controlled Grid fails to meet the requirements defined in Table C-2.

Table C-2: Voltage Criteria
(Bus voltages are relative to the nominal bus voltages of the system under study)

Voltage level	Normal Conditions (TPL-001)		Contingency Conditions (TPL-002 & TPL-003)		Voltage Deviation	
	Vmin (pu)	Vmax (pu)	Vmin (pu)	Vmax (pu)	TPL-002	TPL-003
≤ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 500 kV	1.0	1.05*	0.90	1.1	≤5%	≤10%

*Most of the 500 kV buses have specific requirements.

C.3 Transient Stability Criteria

Transient stability analysis is a time-domain simulation that assesses the performance of the power system during (and shortly following) a system disturbance. Transient stability studies are performed to ensure system stability following severe system disturbances.

The system is considered stable if the following conditions are met:

- All machines in the WECC interconnected system must remain in synchronism as demonstrated by relative rotor angles (unless modeling problems are identified and concurrence is reached that a problem does not really exist);
- A stability simulation will be deemed to exhibit positive damping if a curve defined by the peaks of the machine relative rotor angle swing curves tends to intersect a second curve defined by the valleys of the relative rotor angle swing curves with the passing of time. Corresponding lines on bus voltage swing curves will likewise tend to intersect. A stability simulation, which satisfies these conditions, will be defined as stable;
- Duration of a stability simulation run will be ten (10) seconds unless a longer time is required to ascertain damping;
- The transient performance analysis will start immediately after the fault clearing and conclude at the end of the simulation and;
- A case will be defined as marginally stable if it appears to have zero percent damping and the voltage dips are within (or at) the WECC Reliability Criteria limits.

Performance of the transmission system is measured against the NERC Reliability Standards and WECC Regional Criteria. NERC TPL-001, TPL-002 and TPL-003 require no loss of demand or curtailed firm transfers under Category A and Category B conditions, and planned/controlled loss of demand or curtailed firm transfers under Category C contingencies. Category A, B and C contingencies should not result in cascading outages.

Table C-3 illustrates the WECC reliability criteria. The reliability and performance criteria are applied to the entire WECC transmission system.

Table C-3: WECC Disturbance-Performance Table of Allowable Effects on Other Systems (In addition to the NERC requirements)

NERC and WECC Categories	Outage Frequency Associated with the Performance Category (Outage/Year)	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post-Transient Voltage Deviation Standard (See Note 1)
A	Not Applicable	Nothing in Addition to NERC		
B	≥ 0.33	Not to exceed 25% at load buses or 30% at non-load buses. Not to exceed 20% for more than 20 cycles at load buses.	Not below 59.6 Hz for 6 cycles or more at a load bus	Not to exceed 5% at any bus
C	0.033 – 0.33	Not to exceed 30% at any bus. Not to exceed 20% for more than 40 cycles at load buses.	Not below 59.0 Hz for 6 cycles or more at a load bus	Not to exceed 10% at any bus
D	< 0.033	Nothing in Addition to NERC		

Note 1: As an example in applying the WECC Disturbance-Performance Table, Category B disturbance in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.

C.4 Post-Transient Voltage Stability Criteria

The last column of Table C-3 describes the post-transient voltage stability criteria. The governor power flow is utilized to test for the post-transient voltage deviation criteria.

C.5 Reactive Margin Criteria

Table C-4 summarizes the voltage support and reactive power criteria of requirement R3 of the WECC Regional Criterion TPL-001-WECC-CRT-2. The system performance will be evaluated accordingly.

Table C-4: Reactive Margin Analysis Criteria Summary

Contingency Category	Reactive Power Criteria
B	Voltage stability is required at 105% of load level or transfer path rating
C	Voltage stability is required at 102.5% of load level or transfer path rating

C.6 Power Factor Criteria

Table C-5 summarizes the power factor criteria per the CAISO tariff for the projects.

Table C-5: CAISO Tariff Power Factor Analysis Criteria Summary

Generation Type	Power Factor Criteria
Asynchronous Generator	0.95 lagging to 0.95 leading at the POI[6]
Synchronous Generator	0.90 lagging to 0.95 leading at generator terminals

C.7 Short Circuit Criteria

C.7.1 Application Queue Pre QC5 Phase II Projects

Application queue short circuit duty (SCD) studies were performed to determine the impact on circuit breakers with the interconnection of QC5 Phase II projects to the transmission system. The application queue considered all existing and higher queued generation interconnection projects and corresponding upgrades into the starting base cases as a pre-condition prior to adding the QC5 Phase II projects. In addition, the application queue included all CAISO approved transmission projects and all SCE approved non-CAISO upgrades and system modifications (such as open Mira Loma AA-Bank) into the starting base case as a pre-condition prior to adding the QC5 Phase II projects. The fault duties were calculated to identify any equipment overstress conditions. Three-phase (3PH) and single-line-to-ground (SLG) faults were simulated without the QC5 Phase II projects to establish the starting base line.

The following provide the mitigation details of all identified previously triggered short-circuit duty impacts at locations where duty contributions were increased without the addition of the QC5 Phase II projects.

[6] The CAISO Tariff requires that projects be able to meet power factor requirements of 0.95 lagging and 0.95 leading at the POI, if studies identify the need based on meeting reliability and safety requirements.

C.7.1.1 Vincent 500 kV – Replace the following four 50 kA 500 kV circuit breakers:

- Pos. No.2 CB722
- Pos. No.5 CB752, CB852 and CB952
- Pos. No.6 CB762, CB862, and CB962

C.7.1.2 Windhub 66 kV Substation

- Install a new Windhub 220/66 kV transformer bank
- Install/Open sectionalizing 66 kV circuit breakers to split the 66 kV bus

C.7.2 Application Queue Post QC5 Phase II Projects

The QC5 Phase II projects including the identified Reliability and Local and Area Delivery Network Upgrades from the power flow and stability analysis were added to the starting base line and the fault duties were recalculated to identify the incremental impacts associated with the inclusion of the QC5 Phase II projects.

The short circuit analysis will be performed by simulating single-line-to-ground (1LG) and three-phase (3LG) bus faults as the worst case in a study area, which represents the worst-case conditions to determine the maximum available fault current.

SCE uses the following policy to determine breaker replacement responsibility for cluster projects that overstress or increase overstress on existing circuit breakers:

The fault duties are calculated before and after QC5 projects to identify any equipment overstress conditions. Three-phase (3PH) and single line-to-ground (SLG) faults are simulated without the QC5 projects and with the QC5 projects including the identified Reliability and Local Delivery Network Upgrades from the power flow analysis.

All bus locations where the QC5 projects increases the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are identified. These are examined further to determine if any equipment is overstressed as a result of the QC5 interconnections and corresponding network upgrades.

The responsibility to finance short circuit related Reliability Network Upgrades identified shall be assigned to all contributing Interconnection Requests (projects) pro rata based on their short-circuit duty contribution. Furthermore, if a proposed network upgrade triggers an adverse short circuit impact, the responsibility to finance such short circuit related RNU shall be assigned to the projects contributing to the network upgrade based on the same factors used to allocate the proposed network upgrade cost.

The fault duties are then calculated with the addition of ADNUs for QC5 Option (B) projects. If any equipment is overstressed as a result of the QC5 ADNUs, the responsibility to finance circuit breaker upgrades associated with the ADNUs shall be assigned to the projects requiring the ADNU based on the same factors used to allocate the ADNU. For QC5 Phase II no projects elected Option B, as a result there was no need to calculate fault duties with the addition of ADNUs.

C.7.3 Ground Grid Evaluation of SCE Substations

The short circuit studies identified substations where the QC5 Phase II projects increased the substation ground grid duty by 0.5 kA or more. The SCE substations flagged to have ground grid duty concerns are disclosed in Section D.5 of the QC5 Phase II area group report.

C.8 Deliverability Methodology

C.8.1 On-Peak Deliverability Assessment Methodology

The assessment was performed following the on-peak Deliverability Assessment methodology (http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf). The main steps of the on-peak deliverability assessment are described below.

Screening for Potential Deliverability Problems Using DC Power Flow Tool

A DC transfer capability/contingency analysis tool was used to identify potential deliverability problems. For each analyzed facility, an electrical circle was drawn which includes all generating units including unused Existing Transmission Contract (ETC) injections that have a 5% or greater:

- Distribution factor (DFAX) = (Δ flow on the analyzed facility / Δ output of the generating unit) *100%

  or

- Flow impact = (DFAX * NQC / Applicable rating of the analyzed facility) *100%.

Load flow simulations were performed, which study the worst-case combination of generator output within each 5% Circle.

Verifying and Refining the Analysis Using AC Power Flow Tool

The outputs of capacity units in the 5% Circle were increased starting with units with the largest impact on the transmission facility. No more than twenty units were increased to their maximum output. In addition, no more than 1500 MW of generation was increased. All remaining generation within the Control Area was proportionally displaced, to maintain a load and resource balance.

When the 20 units with the highest impact on the facility can be increased more than 1500 MW, the impact of the remaining amount of generation to be increased was considered using a Facility Loading Adder. The Facility Loading Adder was calculated by taking the remaining MW amount available from the 20 units with the highest impact times the DFAX for each unit. An equivalent MW amount of generation with negative DFAXs was also included in the Facility Loading Adder, up to 20 units. If the net impact from the Facility Loading Adders was negative, the impact was set to zero and the flow on the analyzed facility without applying Facility Loading Adders was reported.

C.8.2 Local Deliverability Constraints and Area Deliverability Constraints

In the Phase II study, the CAISO performed two rounds of deliverability assessments to, first, identify any transmission system operating limits that constrain the deliverability of the modeled generators, and second, determine LDNUs and ADNUs to relieve those constraints. The first round of the deliverability assessment modeled all the generation projects requesting Full

Capacity or Partial Capacity Deliverability Status in accordance with the On-Peak Deliverability Assessment Methodology. The transmission system operating limits identified during the assessment are divided into two categories: local deliverability constraints and area deliverability constraints.

Local deliverability constraints tend to have the following characteristics:

- The generators whose deliverability they constrain (generators inside the 5% DFAX circle) are all located on a few buses electrically close to each other.
- Relieving these constraints does not trigger high cost upgrades.

Area Deliverability Constraints tend to have the following characteristics:

- The generators whose deliverability they constrain (generators inside the 5% DFAX circle) are spread over at least one and possibly more grid study areas or resource areas identified in a resource portfolio used in the TPP.
- In the first round of the Phase II deliverability assessment, relieving these constraints may trigger high cost upgrades, driven by excessively large MW amounts of new generation behind the area deliverability constraint.
- In some potential situations the ISO may classify as an area deliverability constraint a constraint that constrains the deliverability of generators electrically close to each other and is triggered by an exceptionally large volume of generation. This could occur, for example, when there is an exceptionally large volume of Interconnection Requests in a relatively smaller local sub-area within one of the resource development areas identified in the TPP portfolios and relieving the constraint requires expensive upgrades. This potential situation was raised as a concern by some stakeholders, and we determined that in such cases, if they occur, the appropriate remedy would be to reclassify the constraint as an area deliverability constraint based on the recognition that it would serve a substantial volume of generation projects within the study area.

The categorization of ADNU versus LDNU is based on the deliverability constraint that triggers the need of the DNU. With the exception of SPS mitigating deliverability constraints, ADNUs are transmission upgrades or additions to relieve Area Deliverability Constraints and LDNUs are to relieve Local Deliverability Constraints.

C.8.3 Identification of Area Delivery Network Upgrades

The CAISO performs a second round of the deliverability assessment to identify facilities necessary to provide deliverability for Option (B) projects beyond the level of Transmission Plan (TP) Deliverability for each Area Deliverability Constraint.

In the round 2 of the deliverability assessment, all LDNUs and RNUs identified in the round 1 study will be modeled. For each area deliverability constraint, an amount of generation that fully utilizes the TP Deliverability will be identified. Then Option (B) projects will be added to the generation fully utilizing TP Deliverability. ADNUs are identified to provide deliverability for all the Option (B) projects.

C.9 In-Service Date and Commercial Operation Date Assessment Methodology

The QC5 Phase II operational studies examined the following:

- Plan of service in-service date feasibility evaluation
- Generation Sequencing Implementation (GSI) short circuit duty evaluation
- Commercial Operation Date (COD) based operational deliverability assessment

C.9.1 Generation Sequencing Implementation (GSI) Short Circuit Duty Evaluation

The GSI short circuit duty evaluations are broken down into three categories. The description of each of the three categories and their corresponding study assumption is described below:

1. Short term (next 3 years): models generation projects with an executed Interconnection Agreement and approved transmission projects and network upgrades according to their CODs (3 base cases, one for each year)

2. Mid-term: models all generation projects and transmission without the long-lead-time DNUs. Generation projects requiring long-lead-time DNUs are interim EO. (one base case)

3. Long term: will model the long-lead-time DNUs of top of the mid-term DNUs. (one base case)

The GSI short circuit duty evaluation was performed to identify the timing for the need of short-circuit duty mitigations. The evaluation considered seven different scenarios as shown below in Figure C.7.4.

Figure C.7.4 –GSI Short Circuit Duty Evaluation

The details on the GSI short circuit duty assessment are provided in Appendix G.

C.9.2 COD Based Operational Deliverability Assessment

The operational Deliverability Assessment follows the On-Peak Deliverability Assessment methodology. The key components of the operational Deliverability Assessments are discussed below.

Generation Interconnection Project Commercial Operation Date

The assessment models all the active generation projects according to their COD. The latest COD information will be collected as specified below:

- The COD in the Generator Interconnection Agreement (GIA) for executed GIAs or those GIAs that were filed unexecuted at FERC;
- The estimated COD in an approved modification request;
- The estimated COD in the latest study report for projects that have completed the interconnection studies but have not executed the GIA; or
- The requested COD for projects in the current cluster.

The COD will be further scrutinized for feasibility and adjusted if deemed infeasible. Factors used to adjust the COD include:

- Status and progress of the interconnection study or GIA negotiation.
- The estimated time for the Participating TO to complete the Interconnection Facilities and Network Facilities required for the generator interconnection.
- Other information provided by the Interconnection Customer, such as notice to proceed with development of Interconnection Facilities or Network Facilities, and the Generating Facility's permitting, financing and construction status.

The adjusted COD will be used in the operational Deliverability Assessment. In particular, projects that have not signed GIAs or are not under construction are not considered as reasonable to have COD in the next year. The COD for such projects will be adjusted to a later future year based on the factors listed above.

Study Years

The operational Deliverability Assessment will be performed for each applicable future year until the year before all the required Delivery Network Upgrades are scheduled to be in service for the study group.

Modeling Requirements

For each study year, the operational Deliverability Assessment will model the generation projects with adjusted COD in or before the study year and Network Upgrade components that are projected to be in service in or before the study year. In case a generation project will be implemented in phases as defined in the executed GIA, the phasing of the project will be modeled.

The resources, including generation, load, and import, will be modeled in accordance with the On-Peak Deliverability Assessment methodology.

Method for Allocating Deliverable Partial Capacity

Assuming the system conditions cannot accommodate the full deliverability of all generators in the study area that will be in Commercial Operation for the study year, the partial deliverability of each generator is allocated as a function of the Queue Position, generator size, and generator flow impact on the transmission constraint that is binding in the deliverability power flow.

For each deliverability constraint facility, the available capacity without the generation projects being tested is allocated to projects in the order from earlier queued projects to later queued projects until it is depleted. The projects in the same cluster are considered to have the same queue position. If there is available partial capacity for projects in the same cluster, the capacity is allocated using a weighted least square optimization.

The optimization allocation is formulated as:

$$
\begin{aligned}
& Min \sum_{i=1}^{N} \frac{1}{\overline{D_i}} (\overline{D_i} - D_i)^2 \\
& s.t. \quad \sum_{i=1}^{N} D_i \cdot SF_{il} \le C_l, \quad l = 1, \cdots, L \\
& \qquad 0 \le D_i \le \overline{D_i}, \quad i = 1, \cdots, N
\end{aligned}
$$

where

N: number of generators

D_i: Deliverable MW of generator i

$\overline{D_i}$: Upper limit of NQC[7] of generator i

L: number of deliverability constraints

C_l: available capacity on the deliverability constraint l

SF_{il}: shift factor of generator i output on deliverability constraint l

[7] For intermittent generation, a range of output levels between the 20% and 50% production exceedance during summer peak load hours are studied.

D. Reliability Assessment Results

D.1 Steady State Reliability Assessment

This assessment is comprised of Power Flow Analysis and Reactive Power Deficiency Analysis.

Power flow analysis and reactive power deficiency analysis were performed to ensure that SCE's transmission system remains in full compliance with North American Reliability Corporation (NERC) reliability standards TPL-001, 002 and 003, as well as other NERC/WECC reliability standards, with the proposed interconnection. The results of these analyses will serve as documentation that an evaluation of the reliability impact of new facilities and their connections on interconnected transmission systems is performed. The reactive power deficiency analysis also determines whether the asynchronous facilities proposed by the interconnection projects are required to provide 0.95 leading/lagging power factor at the Point of Interconnection.

The study results for this QC5 Phase II Study will be communicated to neighboring entities that may be impacted, for coordination and incorporation of its transmission assessments. Input from neighboring entities is solicited to ensure coordination of transmission systems.

While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, the base cases were developed to represent stressed scenarios of loading and generation conditions for the study group area. The CAISO and SCE cannot guarantee that the QC5 generation projects can operate at maximum rated output, 24 hours a day, year round, without adverse system impacts, nor can the CAISO and SCE guarantee that these projects would not have adverse system impacts during the times and seasons not studied in this Phase II study.

D.1.1 Bulk System Steady State Study

Power Flow Study Results (Category "A", "B" and "C")

Based on the assumptions listed above, the power flow analysis results for Peak and Off-Peak conditions are shown in Table D.1.1.1 and Table D.1.1.2 below.

Table D.1.1.1: Peak Conditions Power Flow Overloads

Over Loaded Component	Rating (Amps)	Pre-Project Loading (Amps / %Rating)	Post-Project Loading (Amps / %Rating)	% Change from Pre-Project Loading	Comment
Category A (N-0) Overloads – Peak					
None					
Category B (N-1) Overloads – Peak					
None					
Category C (N-2) Overloads – Peak					
None					

Table D.1.1.2: Off-Peak Conditions Power Flow Overloads

Over Loaded Component	Rating (Amps)	Pre-Project Loading (Amps / %Rating)	Post-Project Loading (Amps / %Rating)	% Change from Pre-Project Loading	Comment
Category A (N-0) Overloads – Off-Peak					
None					
Category B (N-1) Overloads – Off-Peak					
None					
Category C (N-2) Overloads – Off-Peak					
None					

D.2 Transient Stability Analysis

Transient stability analysis was conducted using both the peak and off-peak full loop base cases to ensure that the transmission system remains stable with the addition of QC5 Phase II generation projects. The generator dynamic data used for the study is confidential in nature and is provided with each individual project report.

Disturbance simulations were performed for a study period of 10 seconds to determine whether the QC5 Phase II projects will create any system instability during a variety of line and generator outages. For SCE's Metro System, selected line and generator outages within the Metro System were evaluated. The outages were consistent with Category B and Category C requirements (single element and multiple element outages).

D.2.1 Bulk System Results

The transient stability study concluded that with the addition of the QC5 Phase II projects proposed system upgrades in place as well as assuming each project can provide 0.95 power factor correction at their POI, the transient stability performance of the system is acceptable. Transient stability plots for peak and off-peak load conditions are provided in Appendix F.

D.3 Post Transient Voltage Stability Assessment

A post-transient voltage stability analysis was performed for this QC5 Phase II Study. The post-transient analysis focused on evaluating the system after the inclusion of all transmission upgrades and the use of the identified SPS, assuming all new generation projects meeting the power factor requirements. Under such conditions, the post-transient study showed acceptable system performance.

D.4 Reliability Assessment Mitigations

Based on the findings of the steady state study no additional Delivery or Distribution Upgrades were triggered in the Metro area by the QC5 Phase II projects.

D.5 Short Circuit Duty Assessment Results

D.5.1 Application Queue Results

The QC5 Phase II Short Circuit Duty (SCD) assessment and breaker evaluations identified that with the inclusion of the Phase II no additional SCD mitigations are required beyond those already triggered by prior queue projects.

D.5.2 Ground Grid Evaluation of SCE Substations Results

The results of the application queue SCD studies were also utilized to identify any SCE substations (CAISO controlled) that may have duty problems on the existing substation ground grid due to the inclusion of the QC5 Phase II projects. The application queue ground grid analysis flagged for further review all existing substations where the QC5 Phase II Projects increased the substation ground grid duty by at least 0.5 kA, The short circuit studies did not flag any SCE substations beyond the point of interconnection with ground grid duty[8] concerns that may necessitate a ground grid study.

D.5.3 Generation Sequencing Implementation (GSI) Short Circuit Duty Assessment Results

The GSI Short Circuit Duty Assessment Results Discussion is provided in Appendix G of this report.

[8] The approximate one-time cost for such study is [redacted] per substation.

D.5.4 In-Service Date and Commercial Operating Date Assessment

The assessment results of the project are identified in Section F of the Phase II Appendix A report.

E. Deliverability Assessment Results

The Deliverability Assessment comprises of on-peak and off-peak deliverability assessments. The ISO Balancing Authority Area (BAA) including the bulk system was monitored for any adverse impacts.

There is no deliverability upgrades identified in this study.

F. Scope of Network Upgrades

The mitigation requirements triggered by QC5 Phase II projects, based on the results described in Sections above, are as follows:

F.1 Plan of Service Reliability Network Upgrades

Plan of Service Reliability Network Upgrades for QC5 projects in the Metro Area are discussed in detail in each individual project report (Appendix A).

F.2 Reliability Network Upgrades

No Reliability Network Upgrades were identified in the QC5 Phase II study in the Metro Area.

F.3 Local Delivery Network Upgrades

No Local Delivery Network Upgrades were identified in the QC5 Phase II study in the Metro Area.

F.4 Distribution Upgrades

No Distribution Upgrades were identified in the QC5 Phase II study in the Metro Area.

G. Cost and Construction Duration Estimates for Upgrades

The cost estimates are based on the published unit costs, when applicable. Customized costs were developed when the unit costs did not reflect the unique circumstances of a project. The customized costs may include: anticipated purchase of land rights, licensing, environmental mitigation, looping lines into substations, new switchyards, substation upgrades not included in unit costs, and SCE's Interconnection Facilities.

Regardless of the requested Commercial Operating Date, the actual Commercial Operation Dates of the generation projects in the QC5 Phase II are dependent on the completed construction and energizing of the identified Network Upgrades. Without these upgrades, the new generators may be subject to CAISO's congestion management, including generation tripping. Based on the needed time for permitting, design, and construction, it may not be feasible to complete all the upgrades needed for this cluster before the requested Commercial Operation Dates.

Costs for each generation project are confidential and are not published in the main body of this report. Each IC is receiving a separate Appendix A report, specific only to that generation project, containing the details of the IC's cost responsibilities.

The total estimated cost of the system upgrades allocated to the Metro area projects are provided in Appendix E.

H. Environmental Evaluation, Permitting, and Licensing

Environmental Evaluation, Permitting, and Licensing information is provided in Appendix K of this report.

I. Items Not Covered in this Report

I.1 Conceptual Plan of Service

The results provided in this study are based on conceptual engineering and a preliminary plan of service and are not sufficient for permitting of facilities. The Plan of Service is subject to change as part of the Final Engineering and Design.

I.2 Customer's Technical Data

The study accuracy and results for the QC5 Phase II Study are contingent upon the accuracy of the technical data provided by the Interconnection Customer. Any changes from the data provided could void the Study results.

I.3 Study Impacts on Neighboring Utilities

Results or consequences of this QC5 Phase II Study and/or to-be-performed Phase II Interconnection Study may require additional studies, facility additions, and/or operating procedures to address impacts to neighboring utilities and/or regional forums. For example, impacts may include but are not limited to WECC Path Ratings, short circuit duties outside of the CAISO Controlled Grid, etc.

I.4 Use of Participating TO Facilities

The Interconnection Customer is responsible for acquiring all property rights necessary for the Interconnection Customer's Interconnection Facilities, including those required to cross PTO facilities and property. This Interconnection Study does not include the method or estimated cost to the Interconnection Customer of PTO mitigation measures that may be required to accommodate any proposed crossing of PTO facilities. The crossing of PTO property rights shall only be permitted upon written agreement between PTO and the Interconnection Customer at PTO's sole determination. Any proposed crossing of PTO property rights will require a separate study and/or evaluation, at the Interconnection Customer's expense, to determine whether such use may be accommodated.

I.5 Participating Transmission Owner Interconnection Handbook

The Interconnection Customer shall be required to adhere to all applicable requirements in the PTO Interconnection Handbook. These include, but are not limited to, all applicable protection, voltage regulation, VAR correction, harmonics, switching and tagging, and metering requirements.

I.6 Western Electricity Coordinating Council (WECC) Policies

The Interconnection Customer shall be required to adhere to all applicable WECC policies including, but not limited to, the WECC Generating Unit Model Validation Policy.

I.7 System Protection Coordination

Adequate Protection coordination will be required between PTO-owned protection and Interconnection Customer-owned protection. If adequate protection coordination cannot be achieved, then modifications to the Interconnection Customer-owned facilities (i.e., Generation-tie or Substation modifications) may be required to allow for ample protection coordination.

I.8 Affected Systems Coordination

The CAISO Generator Interconnection and Deliverability Allocation Procedures (GIDAP) tariff Appendix DD section 3.7 requires that as part of the generator interconnection process, the ISO must regularly coordinate with adjacent electric systems in order to facilitate studies of potential reliability concerns caused by the interconnection of generation in the ISO generation interconnection queue to the ISO controlled grid. Similarly, generators interconnecting to the facilities of transmission owners in adjacent electric systems may cause potential reliability concerns on the ISO controlled grid.

The ISO tariff defines an "Affected System" as an electric system other than the ISO controlled grid that may be affected by the proposed interconnection, and an "Affected System Operator" as the entity operating an Affected System. The ISO tariff provides a general framework for addressing the impact on Affected Systems of generation projects in the ISO interconnection queue. The tariff states that, in the initial project study stages, the ISO will:

- Notify potential Affected System Operators that could be impacted by a generator interconnection;
- Coordinate the conduct of studies to determine possible impacts; and
- Include potential Affected System Operators in all customer meetings.

However, the ISO does not comprehensively study the impacts of generator interconnections on Affected Systems, for several reasons. First, the ISO does not have detailed information about Affected Systems on a transmission-element level, nor does the ISO know the details of the various reliability and operating criteria applicable to the Affected Systems. Second, because the operation of transmission systems changes over time along with NERC reliability standards, the ISO cannot presume to know all of the impacts of these changes on Affected Systems. Consequently, the interconnection customer is responsible for:

- Cooperating with the ISO in all matters related to the Affected System studies;

- Signing a separate study agreement with the Affected System Operator so that potential impacts on the Affected System can be evaluated; and
- Paying for necessary studies and any upgrades necessary to mitigate the impacts of their interconnection on the Affected System.

Further, the Affected System Operator is required to cooperate with the ISO on all matters related to the conduct of studies and modifications to the Affected System.
The interconnection customer is obligated by the terms of the ISO's relevant generator interconnection agreement (large or small) to enter into an agreement with the Affected System Operator, which must specify the terms governing payments for studies and mitigation, if required, to be made by the customer to the Affected System owner, and repayment by the Affected System Operator.

The ISO has advised the Interconnection Customer as to which systems their interconnection is potentially affecting. Prior to its generating unit in-service date, an Interconnection Customer must provide documentation to the ISO confirming that the Affected System Operators have been contacted, that any system reliability impacts have been addressed (or that there are no system impacts), or that the interconnection customer has taken all reasonable steps to address potential reliability system impacts with the Affected System Operator but has been unsuccessful.

I.9 Standby Power and Temporary Construction Power

The QC5 Phase II Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the in-service date of the Interconnection Facilities. Should the Project require standby power or temporary construction power from Participating TO prior to the in-service date of the Interconnection Facilities, the IC is responsible to make appropriate arrangements with Participating TO to receive and pay for such retail.

I.10 Licensing Cost and Estimated Time to Construct Estimate (Duration)

The estimated licensing cost and durations applied to this project are based on the project scope details presented in this study. These estimates are subject to change as project environmental and real estate elements are further defined. Upon execution of the Interconnection Agreement, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

I.11 Network/Non-Network Classification of Telecommunication Facilities

The cost for telecommunication facilities that were identified as part of the IC's Interconnection Facilities was based on an assumption that these facilities would be sited, licensed, and constructed by the IC. The IC will own, operate, maintain, and construct diverse telecommunication paths associated with the IC's gen tie, excluding terminal equipment at both ends. In addition, the telecommunication requirements for SPS were assumed based on tripping of the generator breaker as opposed to tripping the circuit breakers at the PTO substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of QC5 Phase II, telecommunication upgrades for higher queued projects were not considered in this study. Depending on the outcome of interconnection studies for higher queued projects, the telecommunication upgrades identified for QC5 Phase II may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

I.12 Ground Grid Analysis

A detailed ground grid analysis may be required as part of the final engineering for the project at the PTO substations whose ground grids were flagged with duty concerns in Section D.5 of this report.

I.13 Applicability

This document has been prepared to identify the impact(s) contributions of the Project on the PTO electrical system; as well as establish the technical requirements to interconnect the Project to the Point of Interconnection that was evaluated in the QC5 Phase II study for the Project. Nothing in this report is intended to supersede or establish terms/ conditions specified in interconnection agreements agreed to by PTO, CAISO and the Interconnection Customer.

I.14 Potential Changes in Cost Responsibility

The Interconnection Customer is hereby placed on notice that interconnection of its proposed generating facility may be dependent upon certain Network Upgrades which are currently the cost responsibility of projects ahead of the proposed generating facility in the interconnection application queue. In accordance with CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP). Section 14.2.2 of the GIDAP provides that should Network Upgrades required for queued-ahead projects be included in an executed GIA (or unexecuted GIA filed at FERC) at the time of withdrawal of the earlier queued generating facility, and the upgrades are determined to still be needed by later queued generating facilities, the financial responsibility for such upgrades falls to the Participating Transmission Owner. However, if the Network Upgrades required by earlier queued generating facilities are not subject to an executed GIA (or unexecuted GIA filed at FERC) the financial responsibility for such upgrades may fall to the Interconnection Customer. Section 14.2.2 also discusses how Network Upgrades required by interconnection customers selecting Option (B) might be required to be reapportioned among interconnection customers selecting Option (B) in the case of withdrawals of earlier queued generating facilities. Changes in costs allocated to the Interconnection Customer could also arise as the result of the CAISO's reassessment process described in Section 7.4 of the GIDAP. SCE encourages the Interconnection Customer to review Sections 7.4 and 14.2.2 of the GIDAP for the rules and processes under which the financial responsibility might be reapportioned to the Interconnection Customer. Potential changes in the Interconnection Customer's cost responsibility resulting from application of the provisions of these Sections of GIDAP are not included in this Phase II study, nor are the potential impacts to the Interconnection Customer's maximum cost responsibility outlined in this Phase II study.

J. Definitions

ADNU	Area Delivery Network Upgrade
BES	Bulk Electric System
CAISO	California Independent System Operator Corporation
CDWR	California Department of Water Resources
COD	Commercial Operation Date
Deliverability Assessment	CAISO's Deliverability Assessment
EO	Energy-Only Deliverability Status
FC	Full Capacity Deliverability Status
FERC	Federal Energy Regulatory Commission
GIP	Generator Interconnection Procedures
GIDAP	Generator Interconnection and Deliverability Allocation Procedures
IC	Interconnection Customer
IID	Imperial Irrigation District
LDNU	Local Delivery Network Upgrade
LFBs	Local Furnishing Bonds
LGIA	Large Generator Interconnection Agreement
NERC	North American Electric Reliability Corporation
NQC	Net Qualifying Capacity as modeled in the Deliverability Assessment:
PG&E	Pacific Gas and Electric Company
Phase II Study	QC5 Phase II Study
PMax	Maximum generation output
PTO	Participating Transmission Owner
RAS	Remedial Action Scheme (also known as SPS)
POI	Point of Interconnection
POS	Plan of Service
RNU	Reliability Network Upgrade
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SPS	Special Protection System (also known as RAS)
SVC	Static VAr Compensator
SVP	Silicon Valley Power
TPP	CAISO's Transmission Planning Process
TPD	Transmission Plan Deliverability. Deliverability supported by the CAISO's Transmission Plan
VEA	Valley Electric Association
WAPA	Western Area Power Administration
WDT	Wholesale Distribution Tariff
WECC	Western Electricity Coordinating Council

Appendix A

Individual Project Report

Please refer to separate document

Appendix B

System Assumptions

Please refer to separate document

Appendix C

Contingency Lists for Outages

Please refer to separate document

Appendix D

Power Flow Plots

Please refer to separate document

Appendix E

Cost and Construction Duration Estimates for Upgrades

Please refer to separate document

Appendix F

Transient Stability Plots

Please refer to separate document

Appendix G

Generation Sequencing Implementation (GSI) Short Circuit Duty Evaluation Discussion

Please refer to separate document

Appendix H

Short Circuit Calculation Study Results

Please refer to separate document

Appendix I

Deliverability Assessment Results

There is no deliverability upgrade identified.

Appendix J

Affected Systems Coordination

There is no affected system in this study

Appendix K

Environmental Evaluation, Permitting, and Licensing

Please refer to separate document

Appendix A – Q893

AES North America Development, LLC

Huntington Beach

QUEUE CLUSTER 5 PHASE II REPORT

December 3, 2013

This study has been completed in coordination with Southern California Edison per CAISO Tariff Appendix DD Generator Interconnection Procedures and Deliverability Allocation Procedures (GIDAP)

Table of Contents

A. Introduction

AES North America Development, LLC, the Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to the California Independent System Operator Corporation (CAISO) for their proposed Huntington Beach (Project), interconnecting to the CAISO Controlled Grid. The Project is an Option (A)[1] facility, that will utilize two (2) Combine Cycle Generator Blocks (each block consist of three (3) 113.825 MW Gas Turbines & one (1)145.148 MW Steam Turbine)with a total net output of 938.612 MW and a proposed Point of Interconnection (POI) at Southern California Edison Company's (Participating TO) Ellis 220 kV[2] Substation. The IC has requested Full Capacity Deliverability Status, a proposed In-Service Date of January 1, 2018 for Block 1 and June 1, 2019 for Block 2 and a proposed Commercial Operation Date (COD) of January 1, 2019[3] for Block 1 and June 1, 2020 for Block 2.

In accordance with Federal Energy Regulatory Commission (FERC) approved CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP), the Project was grouped with Queue Cluster 5 (QC5) Phase II projects to determine the impacts of the group as well as impacts of the Project on the CAISO Controlled Grid.

The area report has been prepared separately identifying the combined impacts of all projects in the group on the CAISO Controlled Grid. This report focuses only on the impacts or impact contributions of the Project, and it is not intended to supersede any contractual terms or conditions specified in an Interconnection Agreement.

The report provides the following:

1. Transmission system impacts caused by the Project;

2. System reinforcements necessary to mitigate the adverse impacts caused by the Project under various system conditions;

3. A list of required facilities and a good faith estimate of the Project's cost responsibility and time to construct[4] these facilities. Such information is provided in Attachment 2 and Attachment 3 as separate documents in the Appendix A Project report package.

All equipment and facilities comprising the Project located in Huntington Beach, California, as disclosed by the IC in its IR, as may have been amended during the Interconnection Study process, which consists of (i) two (2) Combine Cycle Generator Blocks (each block consist of three (3) 113.825 MW Gas Turbines & one (1)145.148 MW Steam Turbine), (ii) the associated infrastructure, (iii) meters and metering equipment, (iv) appurtenant equipment, and (v) auxiliary loads. The Project shall consist of the Generating Facility and the IC's Interconnection Facilities as illustrated below in Figure A.1.

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[1] Option (A) – Under this option the Generating Facility will receive a TP Deliverability amount for the Project by the CAISO which is determined from the most recent Transmission Plan. The Interconnection Customer will be required take on the cost responsibility assigned to it for IF, Distribution Upgrades, RNUs and LDNUs.

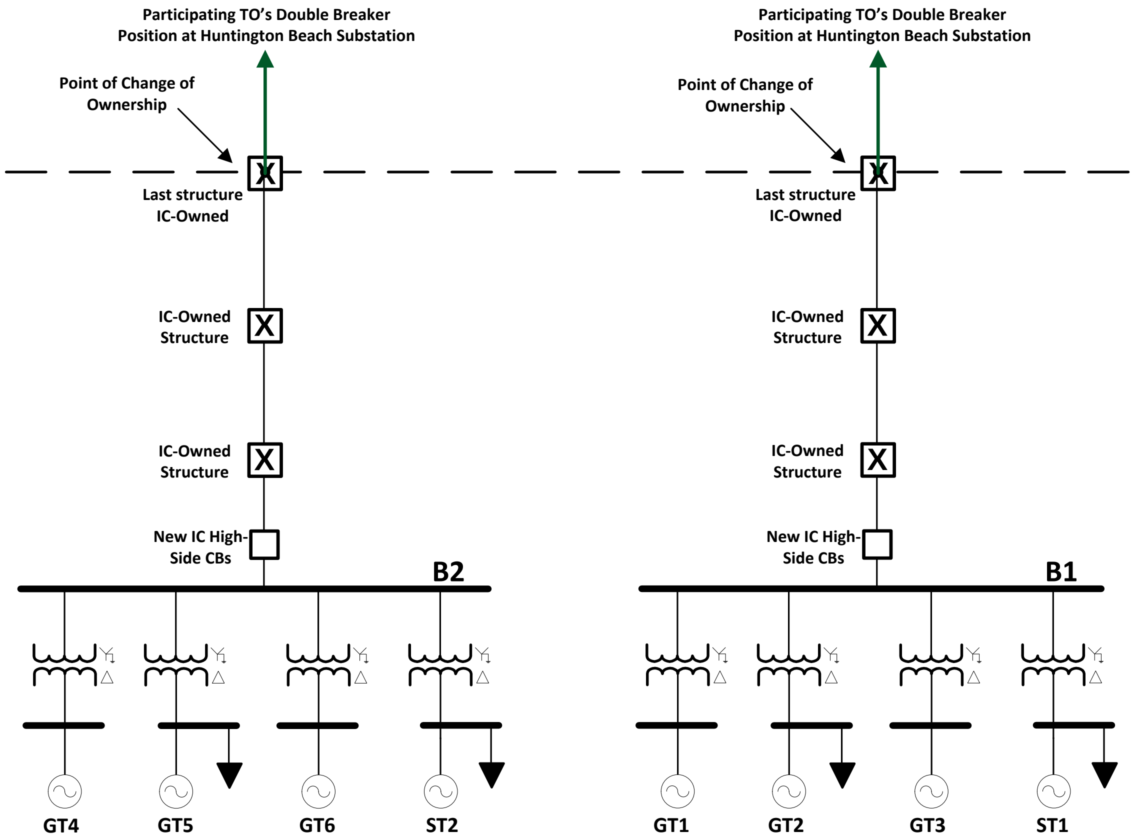
[2] Identification of facility voltages (220 kV) in this QC5 Phase II Study are shown consistent with SCE System Operating Bulletin 123. However, all studies were predicated on the base voltages reflected in the Western Electricity Coordinating Council (WECC) base cases. For the SCE bulk power system, the WECC base cases reflect 230 kV and 500 kV base voltages; consequently, all per-unit calculations presented were based on 230 kV and 500 kV voltages.

[3] Date as requested in the Appendix B. Actual COD depends on design and construction requirements.

[4] It should be noted that construction is only part of the duration of months specified in the study, includes final engineering, licensing, etc, and other activities required to bring such facilities into service. These durations are from the execution of the Interconnection Agreement, receipt of: all required information, funding, and written authorization to proceed from the IC as will be specified in the Interconnection Agreement to commence the work.

Figure A.1: Generating Facility One-line Diagram

DRAWING NOT TO SCALE



<u>Individual Gas Generator Data (6 units):</u>
Individual generator output: 113.825 MW
Base MVA: 119.815 MVA
Voltage Rating: 13.8 kV
PF: 0.95
Xd''1: 0.121 p.u.
X0: 0.082 p.u.

<u>Individual Steam Generator Data (2 units):</u>
Individual generator output: 145.148 MW
Base MVA: 152.787 MVA
Voltage Rating: 13.8 kV
PF: 0.95
Xd''1: 0.14 p.u.
X0: 0.091 p.u.

<u>Transmission Line B1:</u>
Mileage: 0.22 miles, 1033.5 ACSR
Z_1 (p.u.) = 0.000038 + J0.000308
Z_0 (p.u.) = 0.000157 + J0.001064

<u>GT1-6 Individual Transformer Bank (6 units)</u>
Rated Voltage: 230/13.8 kV
Rated MVA: 120 MVA
Impedance: 10% @ 73 MVA
H Winding: Wye-Gnd
X Winding: Delta

<u>ST1 & ST2 Individual Transformer Bank (2 units)</u>
Rated Voltage: 230/13.8 kV
Rated MVA: 153 MVA
Impedance: 10% @93 MVA
H Winding: Wye-Gnd
X Winding: Delta

<u>Transmission Line B2:</u>
Mileage: 0.16 miles, 1033.5 ACSR
Z_1 (p.u.) = 0.000027 + J0.000224
Z_0 (p.u.) = 0.000114 + J0.000774

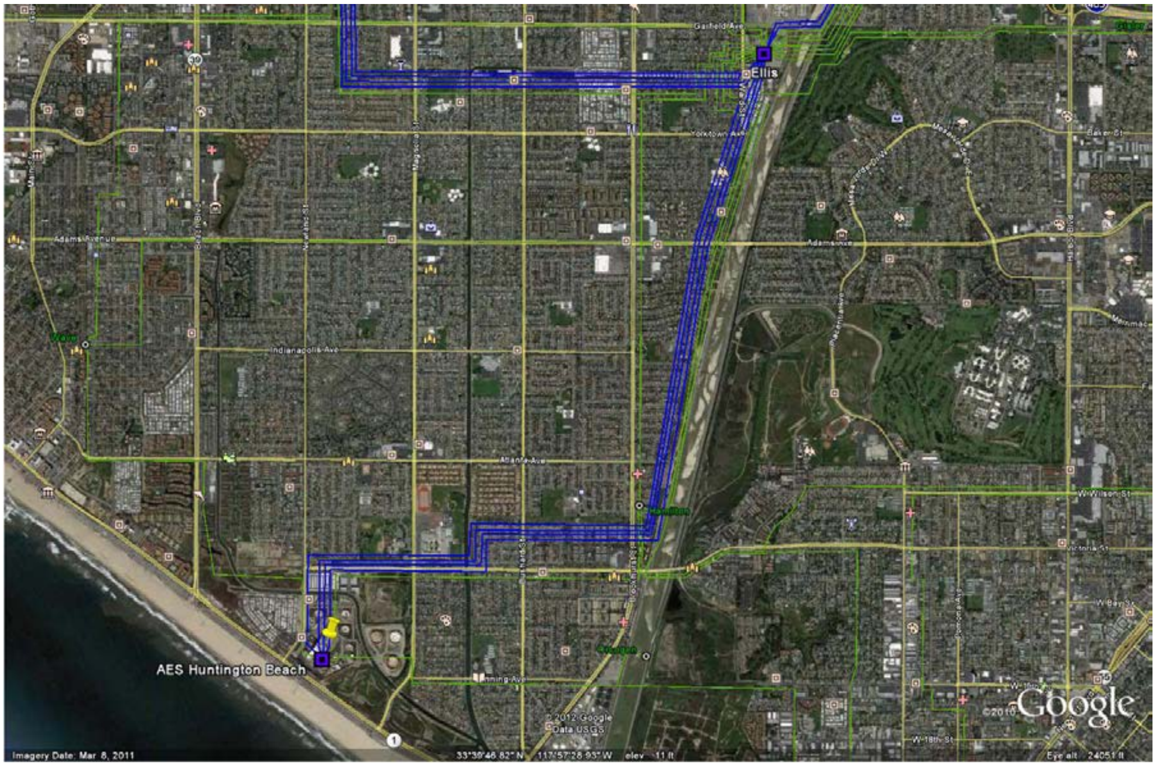
Total Auxiliary Load: 34.634 MW

Table A.1 provides a summary of the Project information and Figure A.2 provides a map of the Project location and transmission facilities in the vicinity.

Table A.1: Project General Information

Project Location	21730 Newland St. Huntington Beach, CA Orange County
Participating TO’s Planning Area	SCE Metro Area
Number and Type of Generators	Two (2) Combine Cycle Generator Blocks (each block consist of three (3) 113.825 MW Gas Turbines & one (1)145.148 MW Steam Turbine)
Interconnection Voltage	220 kV
Maximum Generator Output	973.246 MW
Generator Auxiliary Load	34.634 MW
Maximum Net Output to Grid	938.612 MW
Power Factor Range	Lead 0.95 / Lag 0.90
Step-up Transformer(s)	**Combine Cycle Gas Turbine Transformer:** 220/13.8 kV (YG -D), 73/96/120 MVA H-X Impedance Value: 10 % @ 73 MVA **Combine Cycle Steam Turbine Transformer:** 220/13.8 (YG -D), 93/123/153 MVA H-X Impedance Value: 10 % @ 93 MVA
POI	Participating TO’s Ellis 220 kV Substation
IC Requested COD	Block 1 January 1, 2019 Block 2 June 1, 2020

Figure A.2: Map of the Project



B. Study Assumptions

For detailed assumptions, please refer to QC5 Phase II area report. The following assumptions are only specific to the Project:

1. For the purposes of this report, prior to the repower of the IC's Huntington Beach Generating Facility, the Participating TO owned Huntington Beach 220 kV Substation consisted of a double bus-double breaker 220 kV Substation, whereby the Huntington Beach Generating Facilities units 1, 2, 3 and 4 were connected directly to the Huntington Beach 220 kV Substation buses via motor operated disconnects. As a result of the proposed re-powering of the Huntington Beach Generating Facility and as pursuant to the Participating TO's interconnection standards for new and repowered generating facilities, any and all new or repowered generating facilities must include the following:

- High side circuit breakers and disconnects at the generating facility capable of isolating the generating facility from the Participating TO's electrical system and the CAISO grid.
- All generating tie lines interconnecting into the Participating TO's substation must be terminated with circuit breakers and disconnects.
- All generating tie lines interconnecting into the Participating TO's substation must terminate using either double bus double breaker, breaker and a half or other configuration as determined solely by the Participating TO.

2. In the particular case of the Project, the interconnection configuration must be reconfigured from termination directly to the 220 kV buses to termination to a double bus-double breaker configuration. Therefore, the need to remove the existing generation tie lines and motor operated disconnects currently connecting the generation tie lines to the 220 kV buses directly and reconfiguring the terminations to a double bus-double breaker configuration.

3. The following facilities will be installed by SCE and <u>are included</u> in this Phase II Study:
- The segments of the two (2) 220 kV generation tie line from customer's last structures into and within Huntington Beach Substation property lines.
- The segments of the telecommunication paths inside Huntington Beach Substation property line.
- The required remote terminal unit (RTU) to be installed at the generating facility will be installed by SCE.
- The required retail load meters.

  NOTE: SCE installation <u>does not</u> include metering voltage and current transformers. The SCE meters will be connected to the generator – owned voltage and current transformers to be installed for their CAISO metering.

4. The following facilities are to be installed by the IC and are not included in this Phase II Study:
- The two (2) 220 kV generation tie lines from the Generating Facility to the last structures outside the Huntington Beach Substation property line.
- The primary FO telecommunication cable (OPGW or other) and an additional FO path to provide two diverse telecommunication paths required for the line protection relays.
- One high side circuit breaker per generation block at the IC's facility in accordance with SCE's Interconnection Handbook.
- The IC will demolish and remove all existing facilities including the customer-owned buildings. This assumes that all of the relays and associated equipment in the existing control room will be relocated into the new MEER at Huntington Beach Substation This work will be completed under the existing FSA and no relocation costs are included in this study.
- This study did not take into account phasing of the Project.
- The required CAISO metering equipment (voltage and current transformers, and CAISO meters).
- The metering cabinet to house the required SCE retail meters.

  NOTE: Based on a single CAISO resource metering point for an entire block, the metering voltage and current transformers installed for the CAISO metering will also be used for the SCE owned retail meters. (PT's and CT's to meet SCE specifications.) In the event that a single CAISO resource meter point is not provided, interconnection customer will provide block level single point dedicated retail metering voltage and current transformers, associated disconnects and dedicated enclosure in accordance with SCE standards.
- The following line protection relays to be installed at the Generating Facility end of each 220 kV generation tie line:
  - One G.E. L90 current differential relay, or its equivalent successor, with dual dedicated digital communication channels to Huntington Beach Substation.
  - One SEL 311L current differential relay, or its equivalent successor, with dual dedicated digital communication channels to Huntington Beach Substation.

C. Reliability Standards, Study Criteria and Methodology

The generator interconnection studies will be conducted to ensure the CAISO-controlled grid is in compliance with the North American Electric Reliability Corporation (NERC) reliability standards, WECC regional criteria, and the CAISO planning standards. Refer to Section C of the area report for details of the applicable reliability standards, study criteria and methodology.

D. Reliability Assessment Results

1. Steady State Power Flow Analysis Results

(a) Thermal Overloads

- **Category "A"**
  - None
- **Category "B"**
  - None
- **Category "C"**
  - None

(b) Power Flow Non-Convergence

There were no non-convergence issues identified by the addition of the Project.

(c) Voltage Performance

There were no voltage issues identified by the addition of the Project.

(d) Required Mitigations

With the modeling of all CAISO-approved transmission projects and a number of transmission upgrades needed to support queued ahead Serial Group and Cluster projects in the Metro Area, the study identified that the Metro Area has sufficient transmission capability to accommodate the QC5 Phase II projects without any additional upgrades. However duty concerns were flagged on the existing ground grid at Ellis substation. As a result of this finding, a ground grid study for Ellis substation will be required as part of the final engineering and design of the Project.

2. Short Circuit Analysis

Short circuit studies were performed to determine the fault duty impact of adding the QC5 Phase II projects to the transmission system and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstress conditions. Once overstressed circuit breakers are identified, the fault current contribution from each individual project in QC5 Phase II is determined. Each project in the cluster will be responsible for its share of the upgrade cost based on the rules set forth in CAISO Tariff Appendix Y.

(a) Short Circuit Study Input Data

The following input data provided by the IC and was used in this study:

Individual Combined Cycle Steam Turbine Unit (total of 2 units):

Positive Sequence Subtransient Reactance	X_1''	0.140 p.u.
Negative Sequence Subtransient Reactance	X_2''	0.182 p.u.
Zero Sequence Subtransient Reactance	X_0''	0.091 p.u.

Individual Combined Cycle Gas Turbine Unit (total of 6 units):

Positive Sequence Subtransient Reactance	X_1''	0.121 p.u.
Negative Sequence Subtransient Reactance	X_2''	0.150 p.u.
Zero Sequence Subtransient Reactance	X_0''	0.082 p.u.

Individual Combine Cycle Steam Turbine Transformer (total of 2 units):

Type	Main Transformer(s)
Phase	3
Quantity	2
Capacity, Each	153 MVA
Primary Winding Voltage, Configuration	220,000 V, Wye- GND
Secondary Winding Voltage, Configuration	13,800 V, Delta
H-X Impedance, Base	10% @ 93 MVA

Individual Combine Cycle Gas Turbine Transformer (total of 6 units):

Type	Main Transformer(s)
Phase	3
Quantity	6
Capacity, Each	120 MVA
Primary Winding Voltage, Configuration	220,000 V, Wye- GND
Secondary Winding Voltage, Configuration	13,800 V, Delta
H-X Impedance, Base	10% @ 73 MVA

Generation Tie-Line:

The generation tie line was assumed to be negligible.

(b) Short Circuit Duty Study Results

All bus locations where the QC5 Phase II projects increase the short-circuit duty by 0.1 kA or more and where duty was found to be in excess of 60% of the minimum breaker nameplate rating are listed in the area report (Appendix H). These values have been used to determine if any equipment is overstressed as a result of the inclusion of QC5 Phase II interconnections and corresponding network upgrades, if any.

The responsibility to finance short circuit related Reliability Network Upgrades identified through a Group Study shall be assigned to all Interconnection Requests in that Group Study pro rata on the basis of short circuit duty contribution of each Generating Facility.

As discussed in the area report, the QC5 Phase II breaker evaluation identified overstressed circuit breakers at the following buses. The pro-rata cost allocation for the Project, based on SCD contribution at each location, is also provided:

SCD Mitigation – Table of Network Upgrades

N/A

SCD Mitigation – Table of Distribution Upgrades

N/A

(c) SCE Substations with Ground Grids Duty Concerns

The short circuit studies flagged the need for an Ellis substation ground grid study as part of the final engineering and design of the Project. Otherwise the short circuit duty studies did not flag any SCE substations beyond the POIwith ground grid duty concerns that may necessitate a ground grid study.

(d) Preliminary Protection Requirements

Protection requirements are designed and intended to protect the Participating TO's system only. The preliminary protection requirements were based upon the interconnection plan as shown in the one-line diagram depicted in line item #7 in Attachment 2.

The IC is responsible for the protection of its own system and equipment and must meet the requirements in the Participating TO Interconnection Handbook provided in Attachment 4.

3. Transient Stability Evaluation

Limited transient stability studies were conducted using full loop base cases to ensure that the transmission system remains in operating equilibrium, as well as operating in a coordinated fashion, through abnormal operating conditions after the QC5 Phase II projects begin operation. The generator dynamic data used in the study for the Project is shown in Attachment 6.

(a) Transient Stability Study Scenarios

Disturbance simulations were performed for a study period of 10 seconds to determine whether the QC5 Phase II projects will create any system instability during a variety of line and generator outages. The most critical single contingency and double contingency outage conditions in the Metro Area were evaluated. For the list of specific line and generator outages evaluated, see Appendix C of the area report.

(b) Results

Stability analysis was performed for the Metro Area to identify "relative" as opposed to "absolute" conclusions regarding the stability impacts of this Project. In the limited stability analysis performed there were no transient stability problems identified with the addition of the QC5 Phase II projects in the Metro Area. Stability plots are shown in Appendix F of the group report

4. Reactive Power Deficiency Analysis

(a) Group Study Reactive Power Deficiency Results

There were no reactive power deficiencies identified with the addition of the Project in the Metro Area.

(b) Individual Project Power Factor Requirements

The Project consist of synchronous generators and are required to operate within a 0.95 leading to 0.90 lagging power factor as measured at the generator terminals.

E. Deliverability Assessment Results

See Section E in the area report.

F. In-Service Date and Commercial Operation Date Assessment

1. IC Proposed Project Timelines

The latest information provided by the IC has indicated that the requested generator In-Service Date is January 1, 2018 for Block 1 and June 1, 2019 for Block 2, and a proposed COD of January 1, 2019[5] for Block 1 and June 1, 2020 for Block 2.

2. System Upgrade Timelines for Reliable Interconnection

The Operational Studies identified that the following facilities are required in order to provide for reliable interconnection:

(a) **PTO's Interconnection Facilities**
See Section 1.c of Attachment 2.

(b) **Reliability Network Upgrades**

(i) Plan of Service Reliability Network Upgrades – None.

(ii) Special Protection System (SPS) – None.

(iii) Short-Circuit Duty (SCD) Mitigation

1. Pre-QC5 Phase II Projects
The circuit breaker upgrades that were triggered by queued-ahead projects are identified in Section C.7.1 of the QC5 Phase II area report.

2. Including the QC5 Phase II Projects
The Operational Study undertaken with the inclusion of the QC5 Phase II projects identified the required timing for circuit breaker upgrades and/or SCD mitigation(s) under six different scenarios. These scenarios were selected as the most appropriate operational study conditions and are discussed in Appendix G of the QC5 Phase II area report.

[5] Date as requested in the Appendix B. Actual COD depends on design and construction requirements.

Additionally, the Operational study results, which discuss the timing for breaker upgrades and/or required SCD mitigation(s) at each of the substations identified, are addressed in Appendix G of the QC5 Phase II area report.

It should be noted that the timing of the need for the breaker upgrades and SCD mitigation(s) is dependent on actual timing of generation projects and corresponding upgrades materializing. The identified breaker upgrades and/or SCE mitigation(s) will not adversely impact the COD of the Project. Additional review for the identified breaker upgrades and/or SCE mitigation(s) discussed in Appendix G of the QC5 Phase II area report will be performed to evaluate timing of these breaker replacements and SCD mitigation(s) as projects execute Interconnection Agreements.

(iv) Reactive Support Upgrades – None.

(v) Subtransmission Upgrades – None.

(c) **Distribution Upgrades –** None.

3. System Upgrades Required for Full Capacity Deliverability Status

In order to provide for Full Capacity Deliverability Status, the following facilities are required:

(a) Triggered Delivery Network Upgrades

None

(b) Delivery Network Upgrades Triggered by Earlier Queued Projects

None

(c) Approved Transmission Upgrades

None

(d) Transmission Upgrades outside the CAISO Controlled Grid

None

4. Interim Operational Deliverability Assessment for Information Only

The operational deliverability assessment was performed for study years 2013 and 2014 by modeling the transmission and generation in service in the corresponding study year. For details of the transmission and generation assumption, refer to Section F of the area report. There is no deliverability constraint identified and the Project could have 100% interim deliverability under the year by year transmission and generation assumptions. However, if some or all the transmission upgrades are delayed or more generation is actually in commercial operation than assumed, the interim deliverability of the Project will be impacted.

5. Additional Project Operational Discussion

During the construction of the Huntington Beach Re-power Project, planned outages on Huntington Beach Generation Units 1 and 2 and Synchronous Condenser Units 3 and 4 may be limited to periods as permitted by CAISO's Operating Procedure 7830 or subsequent versions of this procedure. For example, Units 1-4 or equivalent will be required during peak load periods and outages of specific units may only be permitted during low load periods. As a result, close coordination between CAISO, SCE and AES will be required to minimize scheduling conflicts during the construction of the new Huntington Beach Re-power Project.

6. Conclusion

The requested IC In-Service Date of January 1, 2019 for Block 1 and June 1, 2020 for Block 2 can be met due to the anticipated duration of 19 months for the facilities needed to enable Energy Only Interconnection. The specified duration of 19 months is from the day an Interconnection Agreement is executed, payments are made, and notice to proceed with interconnection is provided. However, as mentioned in Section F.5 above, an appropriate sequence to interconnect the Project will be required.

The ability to meet the requested In-Service Date is directly tied to the ability to schedule planned outages on the Huntington Beach generating units, as well as, the Project's timely execution of the Interconnection Agreement, funding of facilities needed for energy only interconnection, and issuance of notice to proceed. Consequently, in order to have a reasonable chance of meeting the requested In-Service Date; the execution of the Interconnection Agreement, submittal of payments, and notice to proceed with Energy Only Interconnection needs to be completed within the time frames prescribed in the applicable Tariff, in addition to having the ample and adequate plan to phase-in the interconnection of the Project in such a manner that avoids degrading the reliability of the grid.

Lastly, please note that the requested Full Capacity Deliverability Status will not be available until the appropriate Deliverability Network Upgrades are placed into service.

G. Interconnection Facilities, Network Upgrades, and Distribution Upgrades

Please see Attachment 2 for the Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades and Distribution Upgrades allocated to the Project.

H. Cost and Construction Duration Estimates

To determine the cost responsibility of each generation project in QC5, the CAISO developed cost allocation factors (Attachment 1) for Reliability Network Upgrades, Local Delivery Network Upgrades and Area Delivery Network Upgrades. Attachment 3 provides the 'constant' 2013 dollars and their escalation to the estimated COD year for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades which the Project was allocated cost. For the QC5 study, the estimated COD is derived by assuming the duration of the work element will begin in June 2014, which is the CAISO Tariff scheduled completion date of the QC5 Phase II Study plus 120 days for the Interconnection Agreement signing period and submittal of required funds by the IC.

I. SCE Technical Requirements

The IC is responsible for the protection of its own system and equipment and must meet the requirements in the Participating TO Interconnection Handbook provided in Attachment 4.

J. Environmental Evaluation, Permitting, and Licensing

Please see Appendix K of the QC5 Phase II area report.

K. Items not covered in this study

1. Conceptual Plan of Service

The results provided in this study are based on conceptual engineering and a preliminary Plan of Service and are not sufficient for permitting of facilities. The Plan of Service is subject to change as part of final engineering and design.

2. IC's Technical Data

The study accuracy and results for the QC5 Phase II Study are contingent upon the accuracy of the technical data provided by the IC. Any changes from the data provided could void the study results.

3. Study Impacts on Neighboring Utilities

Results or consequences of this QC5 Phase II Study may require additional studies, facility additions, and/or operating procedures to address impacts to neighboring utilities and/or regional forums. For example, impacts may include but are not limited to WECC Path Ratings, short circuit duties outside of the CAISO Controlled Grid, and sub-synchronous resonance (SSR).

4. Use of Participating TO Facilities

The IC is responsible for acquiring all property rights necessary for the IC's Interconnection Facilities, including those required to cross Participating TO facilities and property. This Interconnection Study does not include the method or estimated cost to the IC of Participating TO mitigation measures that may be required to accommodate any proposed crossing of Participating TO facilities. The crossing of Participating TO property rights shall only be permitted upon written agreement between Participating TO and the IC at Participating TO's sole determination. Any proposed crossing of Participating TO property rights will require a separate study and/or evaluation, at the IC's expense, to determine whether such use may be accommodated.

5. **Participating TO Interconnection Handbook**

The IC shall be required to adhere to all applicable requirements in the Participating TO Interconnection Handbook. These include, but are not limited to, all applicable protection, voltage regulation, VAR correction, harmonics, switching and tagging, and metering requirements.

6. **Western Electricity Coordinating Council (WECC) Policies**

The IC shall be required to adhere to all applicable WECC policies including, but not limited to, the WECC Generating Unit Model Validation Policy.

7. **System Protection Coordination**

Adequate Protection coordination will be required between Participating TO-owned protection and IC-owned protection. If adequate protection coordination cannot be achieved, then modifications to the IC-owned facilities (i.e., Generation-tie or Substation modifications) may be required to allow for ample protection coordination.

8. **Affected Systems Coordination**

The CAISO Generator Interconnection and Deliverability Allocation Procedures (GIDAP) tariff Appendix DD section 3.7 requires that as part of the generator interconnection process, the ISO must regularly coordinate with adjacent electric systems in order to facilitate studies of potential reliability concerns caused by the interconnection of generation in the ISO generation interconnection queue to the ISO controlled grid. Similarly, generators interconnecting to the facilities of transmission owners in adjacent electric systems may cause potential reliability concerns on the ISO controlled grid.

The ISO tariff defines an "Affected System" as an electric system other than the ISO controlled grid that may be affected by the proposed interconnection, and an "Affected System Operator" as the entity operating an Affected System. The ISO tariff provides a general framework for addressing the impact on Affected Systems of generation projects in the ISO interconnection queue. The tariff states that, in the initial project study stages, the ISO will:

- Notify potential Affected System Operators that could be impacted by a generator interconnection;
- Coordinate the conduct of studies to determine possible impacts; and
- Include potential Affected System Operators in all customer meetings.

However, the ISO does not comprehensively study the impacts of generator interconnections on Affected Systems, for several reasons. First, the ISO does not have detailed information about Affected Systems on a transmission-element level, nor does the ISO know the details of the various reliability and operating criteria applicable to the Affected Systems. Second, because the operation of transmission systems changes over time along with NERC reliability standards, the ISO cannot presume to know all of the impacts of these changes on Affected Systems. Consequently, the interconnection customer is responsible for:

- Cooperating with the ISO in all matters related to the Affected System studies;
- Signing a separate study agreement with the Affected System Operator so that potential impacts on the Affected System can be evaluated; and

- Paying for necessary studies and any upgrades necessary to mitigate the impacts of their interconnection on the Affected System.

Further, the Affected System Operator is required to cooperate with the ISO on all matters related to the conduct of studies and modifications to the Affected System.

The interconnection customer is obligated by the terms of the ISO's relevant generator interconnection agreement (large or small) to enter into an agreement with the Affected System Operator, which must specify the terms governing payments for studies and mitigation, if required, to be made by the customer to the Affected System owner, and repayment by the Affected System Operator.

The ISO has advised the Interconnection Customer as to which systems their interconnection is potentially affecting. Prior to its generating unit in-service date, an Interconnection Customer must provide documentation to the ISO confirming that the Affected System Operators have been contacted, that any system reliability impacts have been addressed (or that there are no system impacts), or that the interconnection customer has taken all reasonable steps to address potential reliability system impacts with the Affected System Operator but has been unsuccessful.

9. Standby Power and Temporary Construction Power

The QC5 Phase II Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the In-Service Date of the Interconnection Facilities. Should the Project require standby power or temporary construction power from Participating TO prior to the In-Service Date of the Interconnection Facilities, the IC is responsible to make appropriate arrangements with Participating TO to receive and pay for such retail.

10. Licensing Cost and Estimated Time to Construct Estimate (Duration)

The estimated licensing cost and durations applied to the Project are based on the Project scope details presented in this study. These estimates are subject to change as Project environmental and real estate elements are further defined. Upon execution of the Interconnection Agreement, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

11. Network/Non-Network Classification of Telecommunication Facilities

The cost for telecommunication facilities that were identified as part of the IC's Interconnection Facilities was based on an assumption that these facilities would be sited, licensed, and constructed by the IC. The IC will own, operate, maintain, and construct diverse telecommunication paths associated with the IC's generation tie line, excluding terminal equipment at both ends. In addition, the telecommunication requirements for SPS were assumed based on tripping of the generator breaker as opposed to tripping the circuit breakers at the Participating TO substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of QC5 Phase II, telecommunication upgrades for higher queued projects were not considered in this study. Depending on the outcome of interconnection studies for higher queued projects, the telecommunication upgrades identified for QC5 Phase II may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

12. Ground Grid Analysis

A detailed ground grid analysis will be required as part of the final engineering for the Project at the SCE substations whose ground grids were flagged with duty concerns in Section D.5. of the area report.

13. Applicability

This document has been prepared to identify the impact(s) contributions of the Project on the SCE electrical system; as well as establish the technical requirements to interconnect the Project to the POI that was evaluated in the QC5 Phase II Study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in Interconnection Agreements agreed to by SCE, CAISO and the IC.

14. Potential Changes in Cost Responsibility

The IC is hereby placed on notice that interconnection of its proposed generating facility may be dependent upon certain Network Upgrades which are currently the cost responsibility of projects ahead of the proposed generating facility in the interconnection application queue. In accordance with CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP). Section 14.2.2 of the GIDAP provides that should Network Upgrades required for queued-ahead projects be included in an executed GIA (or unexecuted GIA filed at FERC) at the time of withdrawal of the earlier queued generating facility, and the upgrades are determined to still be needed by later queued generating facilities, the financial responsibility for such upgrades falls to the Participating Transmission Owner. However, if the Network Upgrades required by earlier queued generating facilities are not subject to an executed GIA (or unexecuted GIA filed at FERC) the financial responsibility for such upgrades may fall to the IC. Section 14.2.2 also discusses how Network Upgrades required by interconnection customers selecting Option (B) might be required to be reapportioned among interconnection customers selecting Option (B) in the case of withdrawals of earlier queued generating facilities. Changes in costs allocated to the IC could also arise as the result of the CAISO's reassessment process described in Section 7.4 of the GIDAP. SCE encourages the IC to review Sections 7.4 and 14.2.2 of the GIDAP for the rules and processes under which the financial responsibility might be reapportioned to the IC. Potential changes in the IC's cost responsibility resulting from application of the provisions of these Sections of GIDAP are not included in this Phase II study, nor are the potential impacts to the IC's maximum cost responsibility outlined in this Phase II study.

Attachment 1

Allocation of Network Upgrades for Cost Estimates

None

Attachment 2

Interconnection Facilities, Network Upgrades and Distribution Upgrades

Please refer to separate document.

Attachment 3

Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades

Please refer to separate document.

Attachment 4

Participating TO Interconnection Handbook

Preliminary Protection Requirements for Interconnection Facilities are outlined in the Participating TO Interconnection Handbook.

Attachment 5

Short Circuit Calculation Study Results

Please refer to the Appendix H of the area report.

Attachment 6

Customer Provided Project Dynamic Data

The following data was submitted by the IC for Dynamic simulation:

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esst1a 96316 "T642GT2 " 13.80 "2 " : #9 "tr" 0.0 "vimax" 999.00 "vimin" -999.00 "tc" 1.000000 "tb" 10.0000 "ka" 190.00 "ta" 0.020000 "vrmax" 6.9210 "vrmin" -6.7000 "kc" 0.050000 "kf" 0.0 "tf" 1.000000 "tc1" 0.0 "tb1" 0.0 "vamax" 999.00 "vamin" -999.00 "ilr" 0.0 "klr" 0.0 "uelin" 0.0 "pssin" 0.0
#gast 96316 "T642GT2 " 13.80 "2 " : #9 mwcap=113.825 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0
gast 96316 "T642GT2 " 13.80 "2 " : #9 mwcap=119 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0
pss2b 96316 "T642GT2 " 13.80 "2 " : #9 "j1" 1.000000 "k1" 96316 "j2" 3.0000 "k2" 96316 "vsi1max" 999.00 "vsi1min" -999.00 "tw1" 2.0000 "tw2" 2.0000 "vsi2max" 999.00 "vsi2min" -999.00 "tw3" 2.0000 "tw4" 2.0000 "t6" 0.020000 "t7" 2.0000 "ks2" 0.200000 "ks3" 1.000000

"t8" 0.0 "t9" 1.000000 "n" 1.000000 "m" 5.0000 "ks1" 5.0000 "t1" 0.200000 "t2" 0.040000 "t3" 0.360000 "t4" 0.120000 "t10" 0.010000 "t11" 0.010000 "vstmax" 999.00 "vstmin" -999.00 "a" 1.000000 "ta" 0.0 "tb" 0.0 "ks4" 1.000000
#
genrou 96317 "T642GT3 " 13.80 "3 " : #9 mva=119.82 "tpdo" 13.1000 "tppdo" 0.0500 "tpqo" 4.0000 "tppqo" 0.0500 "h" 1.28 "d" 0.0000 "ld" 2.12 "lq" 1.94 "lpd" 0.169 "lpq" 0.2 "lppd" 0.121 "ll" 0.078 "s1" 0.1579 "s12" 0.5697 "ra" 0.00082 "rcomp" 0.0000 "xcomp" 0.0000 "accel" 0.0000
esst1a 96317 "T642GT3 " 13.80 "3 " : #9 "tr" 0.0 "vimax" 999.00 "vimin" -999.00 "tc" 1.000000 "tb" 10.0000 "ka" 190.00 "ta" 0.020000 "vrmax" 6.9210 "vrmin" -6.7000 "kc" 0.050000 "kf" 0.0 "tf" 1.000000 "tc1" 0.0 "tb1" 0.0 "vamax" 999.00 "vamin" -999.00 "ilr" 0.0 "klr" 0.0 "uelin" 0.0 "pssin" 0.0
#gast 96317 "T642GT3 " 13.80 "3 " : #9 mwcap=113.825 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0
gast 96317 "T642GT3 " 13.80 "3 " : #9 mwcap=119 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0
pss2b 96317 "T642GT3 " 13.80 "3 " : #9 "j1" 1.000000 "k1" 96317 "j2" 3.0000 "k2" 96317 "vsi1max" 999.00 "vsi1min" -999.00 "tw1" 2.0000 "tw2" 2.0000 "vsi2max" 999.00 "vsi2min" -999.00 "tw3" 2.0000 "tw4" 2.0000 "t6" 0.020000 "t7" 2.0000 "ks2" 0.200000 "ks3" 1.000000 "t8" 0.0 "t9" 1.000000 "n" 1.000000 "m" 5.0000 "ks1" 5.0000 "t1" 0.200000 "t2" 0.040000 "t3" 0.360000 "t4" 0.120000 "t10" 0.010000 "t11" 0.010000 "vstmax" 999.00 "vstmin" -999.00 "a" 1.000000 "ta" 0.0 "tb" 0.0 "ks4" 1.000000
#
genrou 96319 "T642GT4 " 13.80 "4 " : #9 mva=119.82 "tpdo" 13.1000 "tppdo" 0.0500 "tpqo" 4.0000 "tppqo" 0.0500 "h" 1.28 "d" 0.0000 "ld" 2.12 "lq" 1.94 "lpd" 0.169 "lpq" 0.2 "lppd" 0.121 "ll" 0.078 "s1" 0.1579 "s12" 0.5697 "ra" 0.00082 "rcomp" 0.0000 "xcomp" 0.0000 "accel" 0.0000
esst1a 96319 "T642GT4 " 13.80 "4 " : #9 "tr" 0.0 "vimax" 999.00 "vimin" -999.00 "tc" 1.000000 "tb" 10.0000 "ka" 190.00 "ta" 0.020000 "vrmax" 6.9210 "vrmin" -6.7000 "kc" 0.050000 "kf" 0.0 "tf" 1.000000 "tc1" 0.0 "tb1" 0.0 "vamax" 999.00 "vamin" -999.00 "ilr" 0.0 "klr" 0.0 "uelin" 0.0 "pssin" 0.0
#gast 96319 "T642GT4 " 13.80 "4 " : #9 mwcap=113.825 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0
gast 96319 "T642GT4 " 13.80 "4 " : #9 mwcap=119 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0
pss2b 96319 "T642GT4 " 13.80 "4 " : #9 "j1" 1.000000 "k1" 96319 "j2" 3.0000 "k2" 96319 "vsi1max" 999.00 "vsi1min" -999.00 "tw1" 2.0000 "tw2" 2.0000 "vsi2max" 999.00 "vsi2min" -999.00 "tw3" 2.0000 "tw4" 2.0000 "t6" 0.020000 "t7" 2.0000 "ks2" 0.200000 "ks3" 1.000000 "t8" 0.0 "t9" 1.000000 "n" 1.000000 "m" 5.0000 "ks1" 5.0000 "t1" 0.200000 "t2" 0.040000 "t3"

0.360000 "t4" 0.120000 "t10" 0.010000 "t11" 0.010000 "vstmax" 999.00 "vstmin" -999.00 "a" 1.000000 "ta" 0.0 "tb" 0.0 "ks4" 1.000000
#
genrou 96320 "T642GT5 " 13.80 "5 " : #9 mva=119.82 "tpdo" 13.1000 "tppdo" 0.0500 "tpqo" 4.0000 "tppqo" 0.0500 "h" 1.28 "d" 0.0000 "ld" 2.12 "lq" 1.94 "lpd" 0.169 "lpq" 0.2 "lppd" 0.121 "ll" 0.078 "s1" 0.1579 "s12" 0.5697 "ra" 0.00082 "rcomp" 0.0000 "xcomp" 0.0000 "accel" 0.0000
esst1a 96320 "T642GT5 " 13.80 "5 " : #9 "tr" 0.0 "vimax" 999.00 "vimin" -999.00 "tc" 1.000000 "tb" 10.0000 "ka" 190.00 "ta" 0.020000 "vrmax" 6.9210 "vrmin" -6.7000 "kc" 0.050000 "kf" 0.0 "tf" 1.000000 "tc1" 0.0 "tb1" 0.0 "vamax" 999.00 "vamin" -999.00 "ilr" 0.0 "klr" 0.0 "uelin" 0.0 "pssin" 0.0
#gast 96320 "T642GT5 " 13.80 "5 " : #9 mwcap=113.825 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0
gast 96320 "T642GT5 " 13.80 "5 " : #9 mwcap=119 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0
pss2b 96320 "T642GT5 " 13.80 "5 " : #9 "j1" 1.000000 "k1" 96320 "j2" 3.0000 "k2" 96320 "vsi1max" 999.00 "vsi1min" -999.00 "tw1" 2.0000 "tw2" 2.0000 "vsi2max" 999.00 "vsi2min" -999.00 "tw3" 2.0000 "tw4" 2.0000 "t6" 0.020000 "t7" 2.0000 "ks2" 0.200000 "ks3" 1.000000 "t8" 0.0 "t9" 1.000000 "n" 1.000000 "m" 5.0000 "ks1" 5.0000 "t1" 0.200000 "t2" 0.040000 "t3" 0.360000 "t4" 0.120000 "t10" 0.010000 "t11" 0.010000 "vstmax" 999.00 "vstmin" -999.00 "a" 1.000000 "ta" 0.0 "tb" 0.0 "ks4" 1.000000
#
genrou 96321 "T642GT6 " 13.80 "6 " : #9 mva=119.82 "tpdo" 13.1000 "tppdo" 0.0500 "tpqo" 4.0000 "tppqo" 0.0500 "h" 1.28 "d" 0.0000 "ld" 2.12 "lq" 1.94 "lpd" 0.169 "lpq" 0.2 "lppd" 0.121 "ll" 0.078 "s1" 0.1579 "s12" 0.5697 "ra" 0.00082 "rcomp" 0.0000 "xcomp" 0.0000 "accel" 0.0000
esst1a 96321 "T642GT6 " 13.80 "6 " : #9 "tr" 0.0 "vimax" 999.00 "vimin" -999.00 "tc" 1.000000 "tb" 10.0000 "ka" 190.00 "ta" 0.020000 "vrmax" 6.9210 "vrmin" -6.7000 "kc" 0.050000 "kf" 0.0 "tf" 1.000000 "tc1" 0.0 "tb1" 0.0 "vamax" 999.00 "vamin" -999.00 "ilr" 0.0 "klr" 0.0 "uelin" 0.0 "pssin" 0.0
#gast 96321 "T642GT6 " 13.80 "6 " : #9 mwcap=113.825 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0
gast 96321 "T642GT6 " 13.80 "6 " : #9 mwcap=119 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0
pss2b 96321 "T642GT6 " 13.80 "6 " : #9 "j1" 1.000000 "k1" 96321 "j2" 3.0000 "k2" 96321 "vsi1max" 999.00 "vsi1min" -999.00 "tw1" 2.0000 "tw2" 2.0000 "vsi2max" 999.00 "vsi2min" -999.00 "tw3" 2.0000 "tw4" 2.0000 "t6" 0.020000 "t7" 2.0000 "ks2" 0.200000 "ks3" 1.000000 "t8" 0.0 "t9" 1.000000 "n" 1.000000 "m" 5.0000 "ks1" 5.0000 "t1" 0.200000 "t2" 0.040000 "t3"

0.360000 "t4" 0.120000 "t10" 0.010000 "t11" 0.010000 "vstmax" 999.00 "vstmin" -999.00 "a" 1.000000 "ta" 0.0 "tb" 0.0 "ks4" 1.000000
#
genrou 96318"T642ST1 " 13.80 "S1" : #9 mva=152.7870 "tpdo" 12.4000 "tppdo" 0.0500 "tpqo" 3.8000 "tppqo" 0.0500 "h" 1.0900 "d" 0.0000 "ld" 2.2700 "lq" 2.0700 "lpd" 0.1930 "lpq" 0.2300 "lppd" 0.1400 "ll" 0.0770 "s1" 0.1200 "s12" 0.4791 "ra" 0.0007 "rcomp" 0.0000 "xcomp" 0.0000 "accel" 0.0000
esac7b 96318 "T642ST1 " 13.80 "S1" : #9 "tr" 0.0 "kpr" 15.0000 "kir" 1.8800 "kdr" 0.0 "tdr" 0.005000 "vrmax" 3.2000 "vrmin" -3.2000 "kpa" 48.3800 "kia" 0.0 "vamax" 28.1400 "vamin" -23.3200 "kp" 1.000000 "kl" 10000.00 "te" 1.4000 "vfemax" 13.9000 "vemin" 0.0 "ke" 1.000000 "kc" 0.470000 "kd" 0.920000 "kf1" 0.0 "kf2" 0.150000 "kf3" 0.020000 "tf" 1.5000 "e1" 6.9000 "se1" 0.150000 "e2" 9.2000 "se2" 2.0700 "spdmlt" 0.0
#ieeeg1 96318 "T642ST1 " 13.80 "S1" : #9 mwcap=142.0000 "k" 20.0000 "t1" 0.004000 "t2" 0.020000 "t3" 0.350000 "uo" 99.0000 "uc" -99.0000 "pmax" 1.000000 "pmin" 0.0 "t4" 0.060000 "k1" 1.000000 "k2" 0.0 "t5" 0.0 "k3" 0.0 "k4" 0.0 "t6" 0.0 "k5" 0.0 "k6" 0.0 "t7" 0.0 "k7" 0.0 "k8" 0.0 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0
ieeeg1 96318 "T642ST1 " 13.80 "S1" : #9 mwcap=152.0000 "k" 20.0000 "t1" 0.004000 "t2" 0.020000 "t3" 0.350000 "uo" 99.0000 "uc" -99.0000 "pmax" 1.000000 "pmin" 0.0 "t4" 0.060000 "k1" 1.000000 "k2" 0.0 "t5" 0.0 "k3" 0.0 "k4" 0.0 "t6" 0.0 "k5" 0.0 "k6" 0.0 "t7" 0.0 "k7" 0.0 "k8" 0.0 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0
pss2b 96318 "T642ST1 " 13.80 "S1" : #9 "j1" 1.000000 "k1" 96322 "j2" 3.0000 "k2" 96322 "vsi1max" 999.00 "vsi1min" -999.00 "tw1" 2.0000 "tw2" 2.0000 "vsi2max" 999.00 "vsi2min" -999.00 "tw3" 2.0000 "tw4" 2.0000 "t6" 0.020000 "t7" 2.0000 "ks2" 0.200000 "ks3" 1.000000 "t8" 0.0 "t9" 1.000000 "n" 1.000000 "m" 5.0000 "ks1" 5.0000 "t1" 0.200000 "t2" 0.040000 "t3" 0.360000 "t4" 0.120000 "t10" 0.010000 "t11" 0.010000 "vstmax" 999.00 "vstmin" -999.00 "a" 1.000000 "ta" 0.0 "tb" 0.0 "ks4" 1.000000
#
genrou 96322"T642ST2 " 13.80 "S2" : #9 mva=152.7870 "tpdo" 12.4000 "tppdo" 0.0500 "tpqo" 3.8000 "tppqo" 0.0500 "h" 1.0900 "d" 0.0000 "ld" 2.2700 "lq" 2.0700 "lpd" 0.1930 "lpq" 0.2300 "lppd" 0.1400 "ll" 0.0770 "s1" 0.1200 "s12" 0.4791 "ra" 0.0007 "rcomp" 0.0000 "xcomp" 0.0000 "accel" 0.0000
esac7b 96322 "T642ST2 " 13.80 "S2" : #9 "tr" 0.0 "kpr" 15.0000 "kir" 1.8800 "kdr" 0.0 "tdr" 0.005000 "vrmax" 3.2000 "vrmin" -3.2000 "kpa" 48.3800 "kia" 0.0 "vamax" 28.1400 "vamin" -23.3200 "kp" 1.000000 "kl" 10000.00 "te" 1.4000 "vfemax" 13.9000 "vemin" 0.0 "ke" 1.000000 "kc" 0.470000 "kd" 0.920000 "kf1" 0.0 "kf2" 0.150000 "kf3" 0.020000 "tf" 1.5000 "e1" 6.9000 "se1" 0.150000 "e2" 9.2000 "se2" 2.0700 "spdmlt" 0.0
#ieeeg1 96322 "T642ST2 " 13.80 "S2" : #9 mwcap=142.0000 "k" 20.0000 "t1" 0.004000 "t2" 0.020000 "t3" 0.350000 "uo" 99.0000 "uc" -99.0000 "pmax" 1.000000 "pmin" 0.0 "t4" 0.060000 "k1" 1.000000 "k2" 0.0 "t5" 0.0 "k3" 0.0 "k4" 0.0 "t6" 0.0 "k5" 0.0 "k6" 0.0 "t7" 0.0 "k7" 0.0 "k8" 0.0 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0
ieeeg1 96322 "T642ST2 " 13.80 "S2" : #9 mwcap=152.0000 "k" 20.0000 "t1" 0.004000 "t2" 0.020000 "t3" 0.350000 "uo" 99.0000 "uc" -99.0000 "pmax" 1.000000 "pmin" 0.0 "t4" 0.060000 "k1" 1.000000 "k2" 0.0 "t5" 0.0 "k3" 0.0 "k4" 0.0 "t6" 0.0 "k5" 0.0 "k6" 0.0 "t7" 0.0 "k7" 0.0 "k8" 0.0 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0
pss2b 96322 "T642ST2 " 13.80 "S2" : #9 "j1" 1.000000 "k1" 96322 "j2" 3.0000 "k2" 96322 "vsi1max" 999.00 "vsi1min" -999.00 "tw1" 2.0000 "tw2" 2.0000 "vsi2max" 999.00 "vsi2min" -999.00 "tw3" 2.0000 "tw4" 2.0000 "t6" 0.020000 "t7" 2.0000 "ks2" 0.200000 "ks3"

1.000000 "t8" 0.0 "t9" 1.000000 "n" 1.000000 "m"   5.0000 "ks1"   5.0000 "t1" 0.200000 "t2"
0.040000 "t3" 0.360000 "t4" 0.120000 "t10" 0.010000 "t11" 0.010000 "vstmax"   999.00 "vstmin"
-999.00 "a" 1.000000 "ta" 0.0 "tb" 0.0 "ks4" 1.000000
#

Queue Cluster 5 Phase II - Attachment 2

Q893 – Huntington Beach

Interconnection Facilities, Network Upgrades and Distribution Upgrades

Interconnection Facilities, Network Upgrades and Distribution Upgrades

Participating TO's Interconnection Facilities, Network Upgrades and Distribution Upgrades described in this Attachment are based on the Participating TO's preliminary engineering and design. Such descriptions are subject to modification to reflect the actual facilities that are constructed and installed following the Participating TO's final engineering and design, identification of field conditions, and compliance with applicable environmental and permitting requirements.

1. Interconnection Facilities.

(a) **Interconnection Customer's Interconnection Facilities. Interconnection Customer's Owned and Maintained:** The Interconnection Customer shall:

(i) Install a substation with four (4) 230 kV main step-down transformer with 10 percent impedance on 73 MVA base and four (4) 230 kV main step-down transformer with 10 percent impedance on 93 MVA base (total of eight (8) transformers)

(ii) Install two (2) new .22 mile 220 kV generation tie-lines from the Generating Facility to a position designated by the Participating TO, outside of the Participating TO's Huntington Beach (HB) Substation, where Interconnection Customer shall install a structure designed and engineered in accordance with the Participating TO's specifications ("Last Structure"). These generation tie-lines will be referred to as the AES- HB 220 kV Lines. The right-of-way for the AES-HB 220 kV Lines shall extend up to the edge of the HB property line.

(Note: The AES- HB 220 kV Lines name is subject to change by the Participating TO based upon its transmission line naming criteria. Should the AES- HB 220 kV Lines name be changed, the LGIA may be amended to reflect such change.)

(iii) Install optical ground wire ("OPGW or other") to provide one of two telecommunication paths required for the line protection scheme, the Remote Terminal Units ("RTU"), and one of the two required telecommunication paths required for the Special Protection Scheme ("SPS"). A minimum of eight (8) strands within the OPGW shall be provided for the Participating TO's exclusive use into HB Substation.

(iv) Install appropriate single-mode fiber optic cables for the diverse telecommunication paths and panels to terminate the telecommunication fiber optic cables for both diverse telecommunication paths, as specified by the Participating TO to match the telecommunication equipment used by the Participating TO at HB Substation and at the Generating Facility, in order to protect the AES- HB 220 kV Lines. The telecommunications paths shall meet the Applicable Reliability Standards criteria for diversity.

(v) Own, operate and maintain the telecommunication path (including OPGW, any fiber optic cables, and appurtenant facilities), with the exception of the terminal equipment at both HB Substation and at the Generating Facility, which terminal equipment will be installed, owned, operated and maintained by the Participating TO.

(vi) Allow the Participating TO to review the Interconnection Customer's telecommunication equipment design and perform inspections to ensure compatibility with the Participating TO's terminal equipment and protection engineering requirements; allow the Participating TO to perform acceptance testing of the telecommunication equipment and the right to request and/or to perform correction of installation deficiencies.

(vii) Provide required data signals, make available adequate space, facilities, and associated dedicated electrical circuits within a secure building having suitable environmental controls for the installation of the Participating TO's RTU in accordance with the Interconnection Handbook.

(viii) Make available adequate space, facilities, and associated dedicated electrical circuits within a secure building having suitable environmental controls for the installation of the Participating TO's telecommunications terminal equipment in accordance with the Interconnection Handbook.

(ix) Extend the OPGW and diverse single-mode fiber optic cables to the Participating TO's telecommunications terminal equipment specified above.

(x) Install all required ISO-approved compliant metering equipment at the Generating Facility, in accordance with Section 10 of the ISO Tariff.

(xi) Install a revenue metering cabinet and revenue metering equipment (typically, voltage and current transformers) at the Generating Facility to meter the Generating Facility retail load, as specified by the Participating TO. The metering cabinet must be placed at a location that would allow twenty-four hour access for the Participating TO's metering personnel.

(xii) Allow the Participating TO to install, in the revenue metering cabinet provided by the Interconnection Customer, revenue meters and appurtenant equipment required to meter the retail load at the Generating Facility.

(xiii) Install relay protection to be specified by the Participating TO to match the relay protection used by the Participating TO at HB Substation and at the Generating Facility, in order to protect each of the AES- HB 220 kV Lines, as follows:

1. Two (2) current differential relays per line via diversely routed dedicated digital communication channels to HB Substation. The make and type of the current differential relay will be specified by the Participating TO during final engineering of the Project.

(xiv) Install disconnect facilities in accordance with the Participating TO's Interconnection Handbook to comply with the Participating TO's switching and tagging procedures.

(b) **Interconnection Customer's Interconnection Facilities. IC Owned, PTO Maintained:**

(i) The PTO shall remove the following equipment at the 66 kV switchyard:

1. Remove two (2) 66 kV circuit breakers with associated foundations in position 2.
2. Remove four (4) sets of 66 kV disconnect switches with associated foundations in position 2.

3. Remove three (3) 66 kV PTs with associated foundation (pos. 2)
4. Remove approximately 310’ of 1590 MCM ACSR conductor (position 2) for the CBs

(ii) The PTO shall remove the following equipment at the 220 kV switchyard:

1. Remove four (4) 220 kV Motor Operated Disconnect (MOD) switches (units 1, 2, 3 & 4) with associated structures and transmission spans into the 220 kV bus.

(c) **Participating TO’s Interconnection Facilities.** The Participating TO shall**:**

(i) **Substations.**

1. **HB Substation**[1]**.**
   a. Install the interconnection facilities portion of two (2) new 220 kV switchrack positions to terminate the AES- HB 220 kV Transmission Lines. This work includes: One (1) 220 kV dead-end substation structure, three (3) 220 kV coupling capacitor voltage transformers (“CCVTs”) with steel pedestal support structures, and three (3) 220 kV line tie-downs for each gen-tie line.
   b. Install the following protection relays for each gen-tie line: Two (2) current differential relays per line via diversely routed dedicated digital telecommunications channel to the Large Generating Facility.
   c. One MEER building - the construction of this MEER building will house all new relays installed and other relays for Huntington Beach Substation when the demolition of the existing MEER at the customer site takes place.
   d. Four (4) 220 kV circuit breakers (two for each block)
   e. Eight (8)sets of 220 kV disconnect switches (four for each block)
   f. Two (2) grounding switch attachment (one for each block)
   g. Thirty six (36) bus supports (eighteen for each block)
   h. Upgrade cable trench.
2. **Ellis Substation.**
   a. Perform ground grid study

(ii) **AES- HB 220 kV Lines.**
Install appropriate number of transmission tower structures including insulators / hardware assemblies, and appropriate number of spans of conductors between the Last Structure and the substation dead-end rack at the HB 230 kV switchyard. It is expected that the actual location and number of structures and spans will be determined as part of final engineering performed upon execution of the LGIA.

[1] Existing positions are not up to SCE standards, the cable trench at HB substation has to be repaired to provide a safe work environment to install new cables for the two new generation tie lines.

Studies for this project assumed two (2) 230 kV transmission structures and one (1) span per tower (total of 2 spans) spans of conductor and OPGW.

(iii) **Telecommunications.**

1. Install all required light-wave, channel, fiber optic cables and associated equipment (including terminal equipment), supporting diverse protection, RTU and SCADA requirements for the interconnection of the Generating Facility. Notwithstanding that certain telecommunication equipment, including the telecommunications terminal equipment, will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Participating TO shall own, operate and maintain such telecommunication equipment as part of the Participating TO's Interconnection Facilities.
2. Install appropriate length of fiber optic cable including conduit, vaults and/or enclosures from the perimeter of the HB Substation to extend the OPGW or other into the communication room at HB Substation. It is expected that the actual location and length of fiber optic cable, conduit and vaults will be determined as part of final engineering performed upon execution of the LGIA. Studies for this project assumed the installation of approximately 1300 feet of underground fiber optic cable inside 5-inch conduit to extend from the Last Structure into the communication room at HB Substation.
3. Install appropriate length of fiber optic cable including conduit from the Participating TO owned vault or enclosure, where the Interconnection Customer's fiber optic cable is connected to the Participating TO's fiber optic cable ("Last Vault") into the communication room at HB Substation. It is expected that the actual location and length of fiber optic cable, conduit and vaults/enclosures will be determined as part of final engineering performed upon execution of the LGIA. Studies for this project assumed the installation of approximately 1310 feet of underground fiber optic cable inside 5-inch conduit, and one 5-foot by 10-foot Last Vault, to extend the Interconnection Customer's diverse telecommunications from the Interconnection Customer installed and owned pole located outside of the Participating TO's substation, or the Last Vault, into the communication room at HB Substation.

(iv) **Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety.**

Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of the Participating TO's Interconnection Facilities, including any associated telecommunication equipment for the AES- HB 220 kV Lines and telecommunication route.

(v) **Metering.**

Install revenue meters and appurtenant equipment required to meter the retail load at the Generating Facility. Notwithstanding that the meters and appurtenant equipment will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Participating TO shall own, operate and maintain such facilities as part of the Participating TO's Interconnection Facilities. For the purpose of this study it was assumed that the TO's retail backfeed meter(s) will be installed in a shared configuration with block level generation output revenue metering installed and maintained by a CAISO jurisdictional authority providing suitable shared potential and current transformers .

(vi) **Power System Controls.**
Install one (1) RTU at the Generating Facility to monitor typical generation elements such as MW, MVAR, terminal voltage and circuit breaker status for the Generating Facility and plant auxiliary load, and transmit the information received thereby to the Participating TO's grid control center. Notwithstanding that the RTU will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Participating TO shall own, operate and maintain the RTU as part of the Participating TO's Interconnection Facilities.

2. Network Upgrades.

(a) **Stand Alone Network Upgrades**. None.

(b) **Other Network Upgrades.** None.

(i) **Reliability Network Upgrades.** None.

(ii) **Delivery Network Upgrades.**

1. **Area Delivery Network Upgrades.** None.

2. **Local Delivery Network Upgrades.** None.

3. Distribution Upgrades. None.

4. Affected System Upgrades. Not Used.

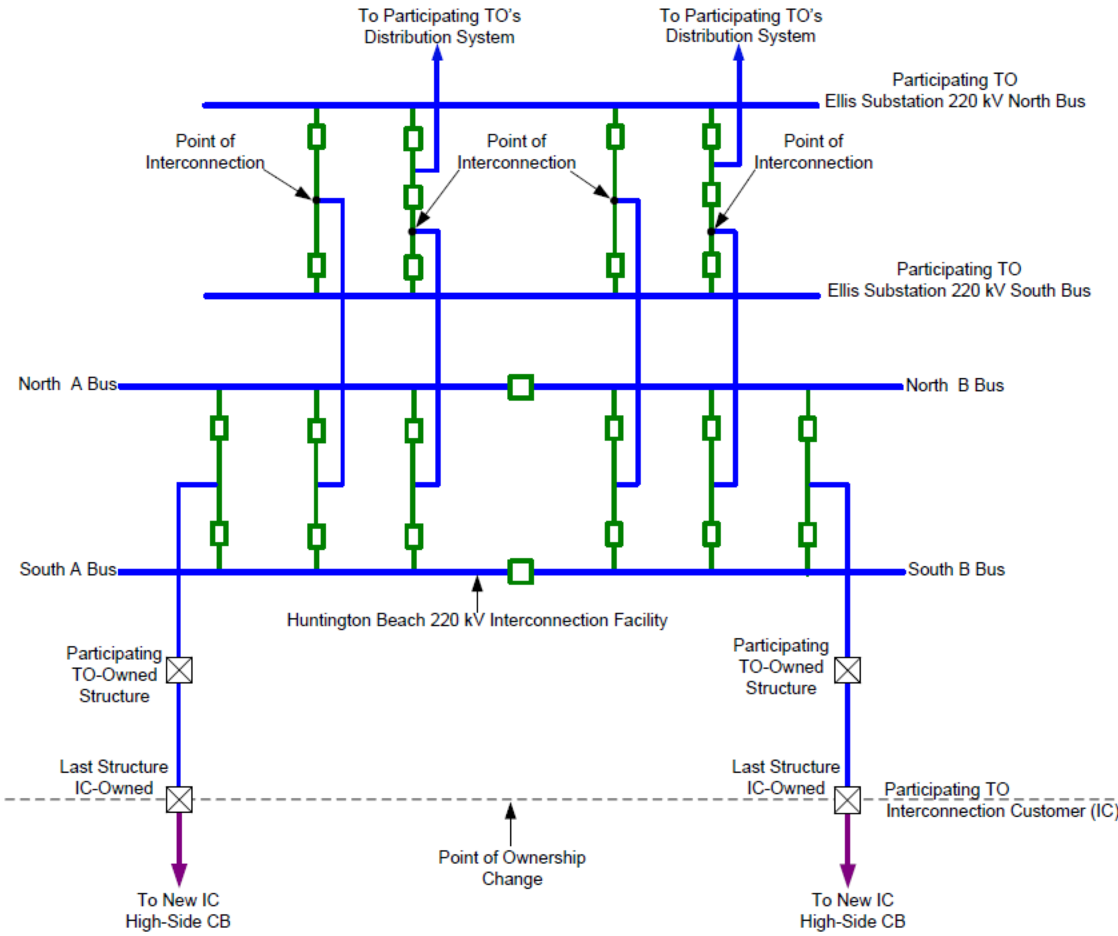
5. Point of Change of Ownership.

(a) AES- HB 220 kV Lines: The Point of Change of Ownership shall be the point where the conductors of the AES- HB 220 kV Lines are attached to the last structure, which will be connected on the side of the Last Structure facing the HB Substation. The Interconnection Customer shall own and maintain the Last Structure, the conductors, insulators and jumper loops from such Last Structure to the Interconnection Customer's Generating Facility. The Participating TO will own and maintain the HB Substation, as well as all circuit breakers, disconnects, relay facilities and metering within the HB Substation, together with the line drop, in their entirety, from the Last Structure to HB Substation. The Participating TO will own the insulators that are used to attach the Participating TO-owned conductors to the last structure.

(b) Telecommunication Primary and Diverse Routes (Including OPGW if used): The Point of Change of Ownership for the telecommunications fiber optics associated with the AES- HB 220 kV Lines shall be at two diverse/separate interface boxes designated by the Participating TO, outside of the Participating TO's Huntington Beach (HB) Substation. Poles, ducts, structures and fiber optic cable meeting primary and diverse route requirements from the Generating Facility to the interface boxes (including F/O cable splicing surplus) shall be owned operated and maintained by the interconnection customer. Fiber optic cable from the interface boxes, ducts, and structures at the perimeter of the HB Substation to the MEER shall be owned operated and maintained by the Participating TO.

6. **Point of Interconnection.** The Participating TO's HB 220 kV Substation at the 220kV bus.

7. One-Line Diagram of Interconnection to Huntington Beach 230kV Substation.



Queue Cluster 5 Phase II

Attachment 3: Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades

Element	Interconnection Facilities Costs x 1,000 Constant Dollar (2013)	Reliability Network Upgrades Costs x 1,000 Constant Dollar (2013)	Delivery Network Upgrades Costs x 1,000 Constant Dollar (2013)	Distribution Upgrades Costs x 1,000 Constant Dollar (2013)	Total Estimated Costs w/o ITCC x 1,000 Constant Dollar (2013)	Total Estimated Costs w/o ITCC x 1,000 Escalated Constant Dollars (OD Year)	"ITCC" x 1,000 Constant Dollar (2013)	Total Estimated Costs w ITCC x 1,000 Constant Dollar (2013)	Total Estimated Costs w ITCC x 1,000 Escalated Constant Dollar (OD Year)	Estimated Time to Construct (Months) (Note 3,4,5, 9, & 10)	OD Dollar Escalation Duration (Months) (Note 3,4,5, 9, & 10)
PTO Interconnection Facilities (Note 1)											
Transmission/Subtransmission Gen-Tie	[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Substation -Equip two(2) 220 kV positions -Install MEER	[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Telecommunication & Edison Carrier Solutions	[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Corporate Enviromental Health and Safety	[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Licensing											
Real Properties	[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Metering Services	[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Power System Controls	[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Subtotal	[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
IC Interconnection Facilities (Note 1)											
Transmission/Subtransmission											
Substation -Equipment Removal	[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Telecommunications/Edison Carrier Solutions											
Corporate Enviromental Services											
Licensing											
Real Properties											
Metering Services											
Power System Controls – Generating Facility											
Subtotal	[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reliability Network Upgrades											
Short Circuit Mitigation - None											
Plan of Service											
Substation											
Telecommunication & Edison Carrier Solutions											
Corporate Enviromental Health and Safety											
Licensing											
Real Properties											
Metering Services											
Power System Controls											
Subtotal											
Local Delivery Network Upgrades											
None											
Subtotal											
Distribution Upgrades (Note 2)											
None											
Subtotal											
Total	[redacted]				[redacted]	[redacted]	[redacted]	[redacted] 0	[redacted]	[redacted]	[redacted]
One Time Costs (Note 1)											
Ground Grid Analysis	[redacted]				[redacted]	[redacted]		[redacted]	[redacted]		[redacted]
Substation- Repair 220 kV Control Cable Trench	[redacted]				[redacted]	[redacted]		[redacted]	[redacted]		[redacted]
Add points to existing RTU at Huntington Beach Generating 220 kV Switchyard	[redacted]				[redacted]	[redacted]		[redacted]	[redacted]		[redacted]
One Time Cost Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q893

Note 1: The Interconnection Customer is obligated to fund these upgrades and will not be reimbursed.

Note 2: Distribution upgrades are not identified in the ISO Tariff, and are not reimbursable. Allocated costs may change if all projects responsible for these upgrades do not execute Generator Interconnection Agreements.

Note 3: The estimated licensing cost and durations applied to this project are based on the project scope details presented in this study. These estimates are subject to change as project environmental and real estate elements are further defined. Upon execution of the Interconnection Agreement, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

Note 4: Each Upgrade category may contain multiple work element construction durations. The longest construction duration is shown under the Estimated Time to Construct.

Note 5: SCE's Phase II cost estimating is done in 'constant' dollars 2013 and then escalated to the estimated O.D.year. For the QC5 study, the estimated O.D. is derived by assuming the duration of the work element will begin in June 2014, which is the CAISO tariff scheduled completion date of the QC5 Phase II study plus 120 days for the interconnection agreement signing period and submittal of required funds by the IC. For instance, if a work element is estimated to take a total of 24 months (final engineering, design, procurement, licensing and construction), then the estimated O.D. would be June 2016. If an IC's requested O.D.(in- service) is beyond the estimated O.D. of a work element, the IC's requested O.D. is used. However, should the Generator Interconnection Agreement not be executed, or the necessary information, funding, and written authorization to proceed is not provided by the IC in time for the Participating TO to perform the work within these time frames, the information provided in Table D.1 may be subject to change.

Note 6: These facilities are not expected to be subject to O&M charges.

Note 7: The Estimated Time to Construct (duration in months) is the schedule for the PTO to complete final engineering, design, procurement, licensing, and construction, etc., and other activities needed to construct and bring the facilities into service. Such activities are from the execution of the Generator Interconnection Agreements, and receipt of: all required information, funding, and written authorization to proceed from the IC, as will be specified in the Generator Interconnection Agreement, to commence work. The estimated schedule does not take into account unanticipated delays or difficulties securing necessary permits, licenses or other approvals; construction difficulties or potential delays in the project implementation process; or unanticipated delays or difficulties in obtaining and receiving necessary clearances for interconnection of the project to the transmission system.

Note 8: The escalation factors to convert the estimated cost (in 'constant' 2013 dollars) to the estimated O.D. are found in the posted SCE 2013 Per Unit Cost Guide on the CAISO website: http://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx

Note 9: Estimated Time to Construct durations are from completion of any preceding facilities required.

Note10: The O.D. dollar for the IF and RNU/Dist. Plan of Service facilties was escalated using the requested Project COD when the requested Project COD was beyond the identified ETC of the IF and RNU/Dist. Plan of Service facilities. In such instances there is a different duration (months) in the ETC and O.D. dollar escalation duration columns.

Queue Cluster 5 Phase II – Appendix B

SCE Metro Area - System Assumptions

Appendix B: Reliability Assessment Assumptions

1. Generation Assumption Tables

Generation assumptions for SCE's Eastern System are shown in Table 1.1 (Existing Generation), Table 1.2 (Active Queued Ahead Serial), Table 1.3 (Transition Cluster), Table 1.4 Pre Queue Cluster 1 and 2 Phase II SGIP projects (Pre QC1&2 Phase II SGIPs), Table 1.5 Pre QC3&4 Phase II projects (Pre QC3&4 Phase II SGIPs), Table 1.6 Queue Cluster 3 and 4 Phase II projects (QC3&4 Phase II), and Table 1.7 summarizes the Rule 21 projects in the area.

In the Reliability Assessment, the generation is initially dispatched at maximum nameplate output as listed in Tables 1.1, 1.2, 1.3, 1.4, 1.5, 1.6, and 1.7. Additional generation dispatch assumptions in the reliability assessment are discussed in the power flow results section of this report.

Table 1.1: Existing Generation

Locations	Type	Size (MW)
Agua Mansa	Simple Cycle -GT	47
Alamitos	Steam	1950
Anaheim	Simple Cycle-GT	50
Barre Peaker	Simple Cycle-GT	47
Broadway	Steam	65
Center Peaker	Simple cycle-GT	47
Century	Simple Cycle-GT	47
Clearwater	Combined Cycle	32
Chevmain	Other	76
Drews	Simple Cycle-GT	47
El Segundo	Steam	670
Etiwanda	Steam	640
Etiwanda Peaker	Simple Cycle-GT	47
Harbor Cogen	Other	110
Huntington Beach	Steam	870
Indigo Peaker	Simple Cycle-GT	182
Inland Empire Energy Center	Combined Cycle	810
Long Beach	Simple Cycle-GT	283
Malburg	Combined Cycle	136
MiraLoma Peaker	Simple Cycle-GT	50
Redondo	Steam	1280
Riverside 1 &2	Simple Cycle-GT	96
Springs	Other	44
	Total (Existing)	**7,626**

Appendix B: Reliability Assessment Assumptions

Table 1.2: Active Queued Ahead Serial Group Interconnection Requests

#	CAISO Queue #	SCE Project ID	Interconnection Point	Size (MW)
1	7	TOT041	El Segundo 220 kV Bus	564
2	66	TOT135	Walnut 220 kV Bus	500.5
3	252	TOT249	Redondo 220 kV Bus	12.7
4	WDAT	WDT086	La Fresa 66 kV	8
5	WDAT	WDT229	Center 66 kV Bus	47.1
6	WDAT	WDT236	Barre 66 kV Bus	47.9
7	WDAT	WDT240	Olinda 12 kV	18.4
8	WDAT	WDT268	Olinda 12 kV	9
			Total	**1,208**

Table 1.3: Transition Cluster Interconnection Requests

#	CAISO Queue #	SCE Project ID	Interconnection Point	Size (MW)
1	383	TOT327	Hinson 220 kV Bus	500
			Total	**2,050**

Table 1.4: Pre QC1&2 Phase II SGIPs Interconnection Request

#	CAISO Queue #	SCE Project ID	Interconnection Point	Size (MW)
1	WDAT	WDT327	Calmen (Chino) 12 kV	1
2	WDAT	WDT356	Bacardi (Mira Loma) 12 kV	1
3	WDAT	WDT358	Bacardi (Mira Loma) 12 kV	2
4	WDAT	WDT359	Seagrams (Mira Loma) 12 kV	2
5	WDAT	WDT364	Seagrams (Mira Loma) 12 kV	0.5
6	WDAT	WDT426	Mosquito (Chino) 12 kV	2
7	WDAT	WDT427	Deacano (Chino) 12 kV	0.75
8	WDT	WDT428	Mosquito (Chino) 12 kV	1.5
9	WDT	WDT429	Deacano (Chino) 12 kV	1.5
			Total	**12.25**

Appendix B: Reliability Assessment Assumptions

Table 1.5: Pre QC3&4 Phase II SGIPs Interconnection Request

#	CAISO QUEUE #	SCE Project ID	Interconnection Point	Size (MW)
1	WDAT	WDT444	Trident (Walnut) 12 kV	1.6
2	WDAT	WDT450	Bacardi (Mira Loma) 12 kV	1
3	WDAT	WDT451	Bacardi (Mira Loma) 12 kV	1
4	WDAT	WDT463	Metro (Padua) 12 kV	1
5	WDAT	WDT464	Absolut (Mira Loma) 12 kV	0.5
6	WDAT	WDT466	Redlabel (Mira Loma) 12 kV	0.5
7	WDAT	WDT471	Andretti (Padua) 12 kV	0.75
8	WDAT	WDT473	Earnhardt (Padua) 12 kV	1.75
9	WDAT	WDT475	Buck (Del Amo) 12 kV	0.75
10	WDAT	WDT478	Zeno (Lighthipe) 12 kV	0.5
11	WDAT	WDT479	Trident (Walnut) 12 kV	0.5
12	WDAT	WDT480	Studebaker (Del Amo) 12 kV	1.16
13	WDAT	WDT481	Loftus (Del Amo) 12 kV	1.25
14	WDAT	WDT482	Orchardale (Del Amo) 12 kV	1.33
15	WDAT	WDT483	Loftus (Del Amo) 12 kV	1.25
16	WDAT	WDT484	Loftus (Del Amo) 12 kV	1.5
17	WDAT	WDT485	Loftus (Del Amo) 12 kV	1
18	WDAT	WDT486	Orchardale (Del Amo) 12 kV	1.75
19	WDAT	WDT525	Pulaski (Mira Loma) 12 kV	1
			Total	**20.09**

Appendix B: Reliability Assessment Assumptions

Table 1.6: QC3&4 Phase II Interconnection Request

#	CAISO QUEUE #	SCE Project ID	Interconnection Point	Size (MW)
1	702	TOT560	El Segundo 220 kV	435
			Total	**435**

Table 1.7: Rule 21 Interconnection Request

#	CAISO QUEUE #	SCE Project ID	System	Size (MW)
1	Rule 21	GFID	Alamitos 220/66 kv	6.25
2	Rule 21	GFID	Chevmain 220/66 kV	46.59
3	Rule 21	GFID	Eagle Rock 220/66 kV	7.5
4	Rule 21	GFID	El Nido 220/66 kV	0.8
5	Rule 21	GFID	Ellis 220/66 kV	0.06
6	Rule 21	GFID	Hinson 220/66 kV	1
7	Rule 21	GFID	La Cienega 220/66 kV	3.46
8	Rule 21	GFID	La Fresa 220/66 kV	1.8
9	Rule 21	GFID	Lighthipe 220/66 kV	0.07
10	Rule 21	GFID	Mira Loma 220/66 kV	4.5
11	Rule 21	GFID	Padua 220/66 kV	3.06
12	Rule 21	GFID	Santiago 220/66 kV	13.38
13	Rule 21	GFID	Viejo 220/66 kV	0.07
14	Rule 21	GFID	Walnut 220/66 kV	3.1
			Total	**91.64**

2. Modeling and Dispatch Assumptions

The study modeled all Metro System QC5 projects with the customer requested plans of service and no system upgrades. All generating units in the Metro area are dispatched at PMax in the study. This study was intended to find whether plan of service issues with QC5 projects would require changes to the customer requested plans of service or points of interconnection.

Appendix B: Reliability Assessment Assumptions

3. Deliverability Study

Table B-1: On-Peak Deliverability Assessment Import Target

Branch Group Name	Direction	Net Import MW	Import Unused ETC & TOR MW
Lugo-Victorville-BG	N-S	1432	141
COI_BG	N-S	3770	548
BLYTHE_BG	E-W	45	0
CASCADE_BG	N-S	36	0
CFE_BG	S-N	-119	0
ELDORADO_MSL	E-W	1213	0
IID-SCE_BG	E-W	1400	0
IID-SDGE_BG	E-W		0
LAUGHLIN_BG	E-W	-38	0
MCCULLGH_MSL	E-W	7	316
MEAD_MSL	E-W	938	455
NGILABK4_BG	E-W	-131	168
NOB_BG	N-S	1208	0
PALOVRDE_MSL	E-W	2872	168
PARKER_BG	E-W	126	28
SILVERPK_BG	E-W	0	0
SUMMIT_BG	E-W	6	0
SYLMAR-AC_MSL	E-W	-164	368
Total		**12599**	**2192**

Metro Area Single Contingencies (N-1)

No.	Contingency Description
1.	SANLUSRY to S.ONOFRE 230.0 kV No.1
2.	SANLUSRY to S.ONOFRE 230.0 kV No.2
3.	SANLUSRY to S.ONOFRE 230.0 kV No.3
4.	TALEGA to S.ONOFRE 230.0 kV No.1
5.	TALEGA to S.ONOFRE 230.0 kV No.1B
6.	TALEGA to S.ONOFRE 230.0 kV No.2
7.	TALEGA to S.ONOFRE 230.0 kV No.2B
8.	ALMITOSE to BARRE 230.0 kV No.1
9.	ALMITOSE to CENTER S 230.0 kV No.1
10.	ALMITOSW to BARRE 230.0 kV No.2
11.	ALMITOSW to LITEHIPE 230.0 kV No.1
12.	ARCO SC to HINSON 230.0 kV No.1
13.	ARCO SC to HINSON 230.0 kV No.2
14.	BARRE to ELLIS 230.0 kV No.1
15.	BARRE to VILLA PK 230.0 kV No.1
16.	BARRE to LEWIS 230.0 kV No.1
17.	CAMINO to MEAD S 230.0 kV No.E
18.	CAMINO to MEAD S 230.0 kV No.W
19.	CAMINO to GENE 230.0 kV No.1
20.	CENTER S to MESA CAL 230.0 kV No.1
21.	CENTER S to OLINDA 230.0 kV No.1
22.	CHINO to MIRALOMW 230.0 kV No.1
23.	CHINO to MIRALOMW 230.0 kV No.2
24.	CHINO to SERRANO 230.0 kV No.1
25.	CHINO to MIRALOME 230.0 kV No.3
26.	DELAMO to CENTER S 230.0 kV No.1
27.	DELAMO to ELLIS 230.0 kV No.1
28.	DELAMO to LAGUBELL 230.0 kV No.1
29.	EAGLROCK to GOULD 230.0 kV No.1
30.	EAGLROCK to MESA CAL 230.0 kV No.1
31.	EAGLROCK to PARDEE 230.0 kV No.1
32.	EAGLROCK to SYLMAR S 230.0 kV No.1
33.	EL NIDO to LA FRESA 230.0 kV No.3
34.	EL NIDO to LA FRESA 230.0 kV No.4
35.	EL NIDO to LCIENEGA 230.0 kV No.1
36.	EL NIDO to CHEVMAIN 230.0 kV No.1
37.	ELLIS to HUNTGBCH 230.0 kV No.1

38.	ELLIS to HUNTGBCH 230.0 kV No.3
39.	ELLIS to JOHANNA 230.0 kV No.1
40.	ELLIS to SANTIAGO 230.0 kV No.1
41.	ELLIS to HUNTBCH1 230.0 kV No.2
42.	ELLIS to HUNTBCH1 230.0 kV No.4
43.	ELSEGNDO to EL NIDO 230.0 kV No.1
44.	ELSEGNDO to CHEVMAIN 230.0 kV No.1
45.	ETIWANDA to MIRALOME 230.0 kV No.1
46.	HARBOR to HINSON 230.0 kV No.1
47.	HARBOR to LBEACH 230.0 kV No.1
48.	HINSON to DELAMO 230.0 kV No.1
49.	JOHANNA to SANTIAGO 230.0 kV No.1
50.	LA FRESA to HINSON 230.0 kV No.1
51.	LA FRESA to LAGUBELL 230.0 kV No.1
52.	LA FRESA to REDONDO 230.0 kV No.1
53.	LA FRESA to REDONDO 230.0 kV No.2
54.	LAGUBELL to RIOHONDO 230.0 kV No.1
55.	LBEACH to LITEHIPE 230.0 kV No.1
56.	LCIENEGA to LA FRESA 230.0 kV No.1
57.	LITEHIPE to HINSON 230.0 kV No.1
58.	LITEHIPE to MESA CAL 230.0 kV No.1
59.	MESA CAL to REDONDO 230.0 kV No.1
60.	MESA CAL to RIOHONDO 230.0 kV No.1
61.	MESA CAL to VINCENT 230.0 kV No.2
62.	MESA CAL to WALNUT 230.0 kV No.1
63.	MIRALOMA to SERRANO 500.0 kV No.1
64.	MIRALOMA to SERRANO 500.0 kV No.2
65.	MIRALOMW to WALNUT 230.0 kV No.1
66.	MIRALOMW to VSTA 230.0 kV No.1
67.	MOORPARK to ORMOND 230.0 kV No.1
68.	MOORPARK to ORMOND 230.0 kV No.2
69.	MOORPARK to ORMOND 230.0 kV No.3
70.	MOORPARK to ORMOND 230.0 kV No.4
71.	OLINDA to WALNUT 230.0 kV No.1
72.	REDONDO to LITEHIPE 230.0 kV No.1
73.	RIOHONDO to VINCENT 230.0 kV No.2
74.	S.ONOFRE to SANTIAGO 230.0 kV No.1
75.	S.ONOFRE to SANTIAGO 230.0 kV No.2
76.	S.ONOFRE to SERRANO 230.0 kV No.1
77.	SERRANO to VILLA PK 230.0 kV No.1
78.	SERRANO to VILLA PK 230.0 kV No.2

79.	SERRANO to VALLEYSC 500.0 kV No.1
80.	SYLMAR S to GOULD 230.0 kV No.1
81.	VINCENT to MESA CAL 230.0 kV No.1
82.	VINCENT to RIOHONDO 230.0 kV No.1
83.	VINCENT to S.CLARA 230.0 kV No.1
84.	VINCENT to MIRALOMA 500.0 kV No.1
85.	VINCENT to VINCTSVC 500.0 kV No.1
86.	RANCHVST to SERRANO 500.0 kV No.1
87.	RANCHVST to MIRALOME 230.0 kV No.1
88.	RANCHVST to MIRALOME 230.0 kV No.2
89.	GOODRICH to GOULD 230.0 kV No.1
90.	GOODRICH to LAGUBELL 230.0 kV No.1
91.	LEWIS to SERRANO 230.0 kV No.1
92.	LEWIS to SERRANO 230.0 kV No.2
93.	LEWIS to VILLA PK 230.0 kV No.1
94.	VIEJOSC to CHINO 230.0 kV No.1
95.	VIEJOSC to S.ONOFRE 230.0 kV No.1
96.	MIRALOME to OLINDA 230.0 kV No.1
97.	MIRALOME to PADUA 230.0 kV No.1
98.	MIRALOME to VSTA 230.0 kV No.2
99.	SYLMAR1 to SYLMAR S 230.0 kV No.1
100.	SERRANO to ALBERHL5 500.0 kV No.1
101.	ALBERHL5 to VALLEYSC 500.0 kV No.1
102.	ALBERHL5 to LEAPS-MP 500.0 kV No.1

Metro Area Single Contingencies (N-2)

No.	Contingency Description
1.	ALMITOSE to BARRE 230.0 kV No.1 & ALMITOSW to BARRE 230.0 kV No.2
2.	ALMITOSE to CENTER S 230.0 kV No.1 & ALMITOSW to BARRE 230.0 kV No.2
3.	ALMITOSE to CENTER S 230.0 kV No.1 & ALMITOSW to LITEHIPE 230.0 kV No.1
4.	ALMITOSE to CENTER S 230.0 kV No.1 & DELAMO to CENTER S 230.0 kV No.1
5.	ALMITOSW to BARRE 230.0 kV No.2 & DELAMO to ELLIS 230.0 kV No.1
6.	ALMITOSW to LITEHIPE 230.0 kV No.1 & HINSON to DELAMO 230.0 kV No.1
7.	BARRE to ELLIS 230.0 kV No.1 & DELAMO to ELLIS 230.0 kV No.1
8.	BARRE to VILLA PK 230.0 kV No.1 & BARRE to LEWIS 230.0 kV No.1
9.	BARRE to VILLA PK 230.0 kV No.1 & LEWIS to VILLA PK 230.0 kV No.1
10.	CENTER S to MESA CAL 230.0 kV No.1 & CENTER S to OLINDA 230.0 kV No.1
11.	CENTER S to MESA CAL 230.0 kV No.1 & MESA CAL to WALNUT 230.0 kV No.1
12.	CENTER S to OLINDA 230.0 kV No.1 & MESA CAL to WALNUT 230.0 kV No.1
13.	CENTER S to OLINDA 230.0 kV No.1 & OLINDA to WALNUT 230.0 kV No.1
14.	CHINO to MIRALOMW 230.0 kV No.1 & CHINO to MIRALOMW 230.0 kV No.2
15.	CHINO to MIRALOMW 230.0 kV No.2 & CHINO to MIRALOME 230.0 kV No.3
16.	CHINO to SERRANO 230.0 kV No.1 & S.ONOFRE to SERRANO 230.0 kV No.1
17.	CHINO to SERRANO 230.0 kV No.1 & VIEJOSC to CHINO 230.0 kV No.1
18.	DELAMO to LAGUBELL 230.0 kV No.1 & HINSON to DELAMO 230.0 kV No.1
19.	DELAMO to LAGUBELL 230.0 kV No.1 & LITEHIPE to MESA CAL 230.0 kV No.1
20.	EL NIDO to LA FRESA 230.0 kV No.3 & EL NIDO to LA FRESA 230.0 kV No.4
21.	EL NIDO to LCIENEGA 230.0 kV No.1 & LCIENEGA to LA FRESA 230.0 kV No.1
22.	EL NIDO to CHEVMAIN 230.0 kV No.1 & ELSEGNDO to EL NIDO 230.0 kV No.1
23.	ELLIS to HUNTGBCH 230.0 kV No.1 & ELLIS to HUNTBCH1 230.0 kV No.2
24.	ELLIS to HUNTGBCH 230.0 kV No.3 & ELLIS to HUNTBCH1 230.0 kV No.2
25.	ELLIS to HUNTGBCH 230.0 kV No.3 & ELLIS to HUNTBCH1 230.0 kV No.4
26.	ELLIS to JOHANNA 230.0 kV No.1 & ELLIS to SANTIAGO 230.0 kV No.1
27.	ELLIS to SANTIAGO 230.0 kV No.1 & JOHANNA to SANTIAGO 230.0 kV No.1
28.	ELSEGNDO to EL NIDO 230.0 kV No.1 & ELSEGNDO to CHEVMAIN 230.0 kV No.1
29.	HARBOR to HINSON 230.0 kV No.1 & LBEACH to LITEHIPE 230.0 kV No.1
30.	HINSON to DELAMO 230.0 kV No.1 & LA FRESA to HINSON 230.0 kV No.1
31.	HINSON to DELAMO 230.0 kV No.1 & LITEHIPE to HINSON 230.0 kV No.1
32.	LA FRESA to HINSON 230.0 kV No.1 & LA FRESA to LAGUBELL 230.0 kV No.1
33.	LA FRESA to HINSON 230.0 kV No.1 & REDONDO to LITEHIPE 230.0 kV No.1
34.	LA FRESA to LAGUBELL 230.0 kV No.1 & LITEHIPE to MESA CAL 230.0 kV No.1
35.	LA FRESA to LAGUBELL 230.0 kV No.1 & MESA CAL to REDONDO 230.0 kV No.1
36.	LA FRESA to LAGUBELL 230.0 kV No.1 & REDONDO to LITEHIPE 230.0 kV No.1
37.	LA FRESA to REDONDO 230.0 kV No.1 & LA FRESA to REDONDO 230.0 kV No.2

38.	LA FRESA to REDONDO 230.0 kV No.2 & MESA CAL to REDONDO 230.0 kV No.1
39.	LAGUBELL to RIOHONDO 230.0 kV No.1 & LITEHIPE to MESA CAL 230.0 kV No.1
40.	LAGUBELL to RIOHONDO 230.0 kV No.1 & MESA CAL to RIOHONDO 230.0 kV No.1
41.	LBEACH to LITEHIPE 230.0 kV No.1 & LITEHIPE to HINSON 230.0 kV No.1
42.	LITEHIPE to MESA CAL 230.0 kV No.1 & GOODRICH to LAGUBELL 230.0 kV No.1
43.	MESA CAL to REDONDO 230.0 kV No.1 & REDONDO to LITEHIPE 230.0 kV No.1
44.	MESA CAL to REDONDO 230.0 kV No.1 & GOODRICH to LAGUBELL 230.0 kV No.1
45.	MESA CAL to RIOHONDO 230.0 kV No.1 & MESA CAL to WALNUT 230.0 kV No.1
46.	MESA CAL to WALNUT 230.0 kV No.1 & OLINDA to WALNUT 230.0 kV No.1
47.	MIRALOMA to SERRANO 500.0 kV No.1 & MIRALOMA to SERRANO 500.0 kV No.2
48.	MIRALOMA to SERRANO 500.0 kV No.1 & MIRALOME to OLINDA 230.0 kV No.1
49.	MIRALOMW to WALNUT 230.0 kV No.1 & OLINDA to WALNUT 230.0 kV No.1
50.	MIRALOMW to WALNUT 230.0 kV No.1 & MIRALOME to OLINDA 230.0 kV No.1
51.	MOORPARK to ORMOND 230.0 kV No.1 & MOORPARK to ORMOND 230.0 kV No.2
52.	MOORPARK to ORMOND 230.0 kV No.2 & MOORPARK to ORMOND 230.0 kV No.3
53.	MOORPARK to ORMOND 230.0 kV No.3 & MOORPARK to ORMOND 230.0 kV No.4
54.	OLINDA to WALNUT 230.0 kV No.1 & MIRALOME to OLINDA 230.0 kV No.1
55.	RIOHONDO to VINCENT 230.0 kV No.2 & VINCENT to RIOHONDO 230.0 kV No.1
56.	S.ONOFRE to SANTIAGO 230.0 kV No.1 & S.ONOFRE to SANTIAGO 230.0 kV No.2
57.	S.ONOFRE to SANTIAGO 230.0 kV No.2 & S.ONOFRE to SERRANO 230.0 kV No.1
58.	S.ONOFRE to SERRANO 230.0 kV No.1 & SERRANO to VALLEYSC 500.0 kV No.1
59.	S.ONOFRE to SERRANO 230.0 kV No.1 & VIEJOSC to CHINO 230.0 kV No.1
60.	S.ONOFRE to SERRANO 230.0 kV No.1 & VIEJOSC to S.ONOFRE 230.0 kV No.1
61.	SERRANO to VILLA PK 230.0 kV No.1 & SERRANO to VILLA PK 230.0 kV No.2
62.	SERRANO to VILLA PK 230.0 kV No.2 & LEWIS to SERRANO 230.0 kV No.2
63.	RANCHVST to MIRALOME 230.0 kV No.1 & RANCHVST to MIRALOME 230.0 kV No.2
64.	LEWIS to SERRANO 230.0 kV No.1 & LEWIS to SERRANO 230.0 kV No.2
65.	LEWIS to SERRANO 230.0 kV No.1 & LEWIS to VILLA PK 230.0 kV No.1

Metro Area Single Contingencies (N-1)

No.	Contingency Description
1.	SANLUSRY to S.ONOFRE 230.0 kV No.1
2.	SANLUSRY to S.ONOFRE 230.0 kV No.2
3.	SANLUSRY to S.ONOFRE 230.0 kV No.3
4.	TALEGA to S.ONOFRE 230.0 kV No.1
5.	TALEGA to S.ONOFRE 230.0 kV No.1B
6.	TALEGA to S.ONOFRE 230.0 kV No.2
7.	TALEGA to S.ONOFRE 230.0 kV No.2B
8.	ALMITOSE to BARRE 230.0 kV No.1
9.	ALMITOSE to CENTER S 230.0 kV No.1
10.	ALMITOSW to BARRE 230.0 kV No.2
11.	ALMITOSW to LITEHIPE 230.0 kV No.1
12.	ARCO SC to HINSON 230.0 kV No.1
13.	ARCO SC to HINSON 230.0 kV No.2
14.	BARRE to ELLIS 230.0 kV No.1
15.	BARRE to VILLA PK 230.0 kV No.1
16.	BARRE to LEWIS 230.0 kV No.1
17.	CAMINO to MEAD S 230.0 kV No.E
18.	CAMINO to MEAD S 230.0 kV No.W
19.	CAMINO to GENE 230.0 kV No.1
20.	CENTER S to MESA CAL 230.0 kV No.1
21.	CENTER S to OLINDA 230.0 kV No.1
22.	CHINO to MIRALOMW 230.0 kV No.1
23.	CHINO to MIRALOMW 230.0 kV No.2
24.	CHINO to SERRANO 230.0 kV No.1
25.	CHINO to MIRALOME 230.0 kV No.3
26.	DELAMO to CENTER S 230.0 kV No.1
27.	DELAMO to ELLIS 230.0 kV No.1
28.	DELAMO to LAGUBELL 230.0 kV No.1
29.	EAGLROCK to GOULD 230.0 kV No.1
30.	EAGLROCK to MESA CAL 230.0 kV No.1
31.	EAGLROCK to PARDEE 230.0 kV No.1
32.	EAGLROCK to SYLMAR S 230.0 kV No.1
33.	EL NIDO to LA FRESA 230.0 kV No.3
34.	EL NIDO to LA FRESA 230.0 kV No.4
35.	EL NIDO to LCIENEGA 230.0 kV No.1
36.	EL NIDO to CHEVMAIN 230.0 kV No.1
37.	ELLIS to HUNTGBCH 230.0 kV No.1

38.	ELLIS to HUNTGBCH 230.0 kV No.3
39.	ELLIS to JOHANNA 230.0 kV No.1
40.	ELLIS to SANTIAGO 230.0 kV No.1
41.	ELLIS to HUNTBCH1 230.0 kV No.2
42.	ELLIS to HUNTBCH1 230.0 kV No.4
43.	ELSEGNDO to EL NIDO 230.0 kV No.1
44.	ELSEGNDO to CHEVMAIN 230.0 kV No.1
45.	ETIWANDA to MIRALOME 230.0 kV No.1
46.	HARBOR to HINSON 230.0 kV No.1
47.	HARBOR to LBEACH 230.0 kV No.1
48.	HINSON to DELAMO 230.0 kV No.1
49.	JOHANNA to SANTIAGO 230.0 kV No.1
50.	LA FRESA to HINSON 230.0 kV No.1
51.	LA FRESA to LAGUBELL 230.0 kV No.1
52.	LA FRESA to REDONDO 230.0 kV No.1
53.	LA FRESA to REDONDO 230.0 kV No.2
54.	LAGUBELL to RIOHONDO 230.0 kV No.1
55.	LBEACH to LITEHIPE 230.0 kV No.1
56.	LCIENEGA to LA FRESA 230.0 kV No.1
57.	LITEHIPE to HINSON 230.0 kV No.1
58.	LITEHIPE to MESA CAL 230.0 kV No.1
59.	MESA CAL to REDONDO 230.0 kV No.1
60.	MESA CAL to RIOHONDO 230.0 kV No.1
61.	MESA CAL to VINCENT 230.0 kV No.2
62.	MESA CAL to WALNUT 230.0 kV No.1
63.	MIRALOMA to SERRANO 500.0 kV No.1
64.	MIRALOMA to SERRANO 500.0 kV No.2
65.	MIRALOMW to WALNUT 230.0 kV No.1
66.	MIRALOMW to VSTA 230.0 kV No.1
67.	MOORPARK to ORMOND 230.0 kV No.1
68.	MOORPARK to ORMOND 230.0 kV No.2
69.	MOORPARK to ORMOND 230.0 kV No.3
70.	MOORPARK to ORMOND 230.0 kV No.4
71.	OLINDA to WALNUT 230.0 kV No.1
72.	REDONDO to LITEHIPE 230.0 kV No.1
73.	RIOHONDO to VINCENT 230.0 kV No.2
74.	S.ONOFRE to SANTIAGO 230.0 kV No.1
75.	S.ONOFRE to SANTIAGO 230.0 kV No.2
76.	S.ONOFRE to SERRANO 230.0 kV No.1
77.	SERRANO to VILLA PK 230.0 kV No.1
78.	SERRANO to VILLA PK 230.0 kV No.2

79.	SERRANO to VALLEYSC 500.0 kV No.1
80.	SYLMAR S to GOULD 230.0 kV No.1
81.	VINCENT to MESA CAL 230.0 kV No.1
82.	VINCENT to RIOHONDO 230.0 kV No.1
83.	VINCENT to S.CLARA 230.0 kV No.1
84.	VINCENT to MIRALOMA 500.0 kV No.1
85.	VINCENT to VINCTSVC 500.0 kV No.1
86.	RANCHVST to SERRANO 500.0 kV No.1
87.	RANCHVST to MIRALOME 230.0 kV No.1
88.	RANCHVST to MIRALOME 230.0 kV No.2
89.	GOODRICH to GOULD 230.0 kV No.1
90.	GOODRICH to LAGUBELL 230.0 kV No.1
91.	LEWIS to SERRANO 230.0 kV No.1
92.	LEWIS to SERRANO 230.0 kV No.2
93.	LEWIS to VILLA PK 230.0 kV No.1
94.	VIEJOSC to CHINO 230.0 kV No.1
95.	VIEJOSC to S.ONOFRE 230.0 kV No.1
96.	MIRALOME to OLINDA 230.0 kV No.1
97.	MIRALOME to PADUA 230.0 kV No.1
98.	MIRALOME to VSTA 230.0 kV No.2
99.	SYLMAR1 to SYLMAR S 230.0 kV No.1
100.	SERRANO to ALBERHL5 500.0 kV No.1
101.	ALBERHL5 to VALLEYSC 500.0 kV No.1
102.	ALBERHL5 to LEAPS-MP 500.0 kV No.1

Metro Area Single Contingencies (N-2)

No.	Contingency Description
1.	ALMITOSE to BARRE 230.0 kV No.1 & ALMITOSW to BARRE 230.0 kV No.2
2.	ALMITOSE to CENTER S 230.0 kV No.1 & ALMITOSW to BARRE 230.0 kV No.2
3.	ALMITOSE to CENTER S 230.0 kV No.1 & ALMITOSW to LITEHIPE 230.0 kV No.1
4.	ALMITOSE to CENTER S 230.0 kV No.1 & DELAMO to CENTER S 230.0 kV No.1
5.	ALMITOSW to BARRE 230.0 kV No.2 & DELAMO to ELLIS 230.0 kV No.1
6.	ALMITOSW to LITEHIPE 230.0 kV No.1 & HINSON to DELAMO 230.0 kV No.1
7.	BARRE to ELLIS 230.0 kV No.1 & DELAMO to ELLIS 230.0 kV No.1
8.	BARRE to VILLA PK 230.0 kV No.1 & BARRE to LEWIS 230.0 kV No.1
9.	BARRE to VILLA PK 230.0 kV No.1 & LEWIS to VILLA PK 230.0 kV No.1
10.	CENTER S to MESA CAL 230.0 kV No.1 & CENTER S to OLINDA 230.0 kV No.1
11.	CENTER S to MESA CAL 230.0 kV No.1 & MESA CAL to WALNUT 230.0 kV No.1
12.	CENTER S to OLINDA 230.0 kV No.1 & MESA CAL to WALNUT 230.0 kV No.1
13.	CENTER S to OLINDA 230.0 kV No.1 & OLINDA to WALNUT 230.0 kV No.1
14.	CHINO to MIRALOMW 230.0 kV No.1 & CHINO to MIRALOMW 230.0 kV No.2
15.	CHINO to MIRALOMW 230.0 kV No.2 & CHINO to MIRALOME 230.0 kV No.3
16.	CHINO to SERRANO 230.0 kV No.1 & S.ONOFRE to SERRANO 230.0 kV No.1
17.	CHINO to SERRANO 230.0 kV No.1 & VIEJOSC to CHINO 230.0 kV No.1
18.	DELAMO to LAGUBELL 230.0 kV No.1 & HINSON to DELAMO 230.0 kV No.1
19.	DELAMO to LAGUBELL 230.0 kV No.1 & LITEHIPE to MESA CAL 230.0 kV No.1
20.	EL NIDO to LA FRESA 230.0 kV No.3 & EL NIDO to LA FRESA 230.0 kV No.4
21.	EL NIDO to LCIENEGA 230.0 kV No.1 & LCIENEGA to LA FRESA 230.0 kV No.1
22.	EL NIDO to CHEVMAIN 230.0 kV No.1 & ELSEGNDO to EL NIDO 230.0 kV No.1
23.	ELLIS to HUNTGBCH 230.0 kV No.1 & ELLIS to HUNTBCH1 230.0 kV No.2
24.	ELLIS to HUNTGBCH 230.0 kV No.3 & ELLIS to HUNTBCH1 230.0 kV No.2
25.	ELLIS to HUNTGBCH 230.0 kV No.3 & ELLIS to HUNTBCH1 230.0 kV No.4
26.	ELLIS to JOHANNA 230.0 kV No.1 & ELLIS to SANTIAGO 230.0 kV No.1
27.	ELLIS to SANTIAGO 230.0 kV No.1 & JOHANNA to SANTIAGO 230.0 kV No.1
28.	ELSEGNDO to EL NIDO 230.0 kV No.1 & ELSEGNDO to CHEVMAIN 230.0 kV No.1
29.	HARBOR to HINSON 230.0 kV No.1 & LBEACH to LITEHIPE 230.0 kV No.1
30.	HINSON to DELAMO 230.0 kV No.1 & LA FRESA to HINSON 230.0 kV No.1
31.	HINSON to DELAMO 230.0 kV No.1 & LITEHIPE to HINSON 230.0 kV No.1
32.	LA FRESA to HINSON 230.0 kV No.1 & LA FRESA to LAGUBELL 230.0 kV No.1
33.	LA FRESA to HINSON 230.0 kV No.1 & REDONDO to LITEHIPE 230.0 kV No.1
34.	LA FRESA to LAGUBELL 230.0 kV No.1 & LITEHIPE to MESA CAL 230.0 kV No.1
35.	LA FRESA to LAGUBELL 230.0 kV No.1 & MESA CAL to REDONDO 230.0 kV No.1
36.	LA FRESA to LAGUBELL 230.0 kV No.1 & REDONDO to LITEHIPE 230.0 kV No.1
37.	LA FRESA to REDONDO 230.0 kV No.1 & LA FRESA to REDONDO 230.0 kV No.2

38.	LA FRESA to REDONDO 230.0 kV No.2 & MESA CAL to REDONDO 230.0 kV No.1
39.	LAGUBELL to RIOHONDO 230.0 kV No.1 & LITEHIPE to MESA CAL 230.0 kV No.1
40.	LAGUBELL to RIOHONDO 230.0 kV No.1 & MESA CAL to RIOHONDO 230.0 kV No.1
41.	LBEACH to LITEHIPE 230.0 kV No.1 & LITEHIPE to HINSON 230.0 kV No.1
42.	LITEHIPE to MESA CAL 230.0 kV No.1 & GOODRICH to LAGUBELL 230.0 kV No.1
43.	MESA CAL to REDONDO 230.0 kV No.1 & REDONDO to LITEHIPE 230.0 kV No.1
44.	MESA CAL to REDONDO 230.0 kV No.1 & GOODRICH to LAGUBELL 230.0 kV No.1
45.	MESA CAL to RIOHONDO 230.0 kV No.1 & MESA CAL to WALNUT 230.0 kV No.1
46.	MESA CAL to WALNUT 230.0 kV No.1 & OLINDA to WALNUT 230.0 kV No.1
47.	MIRALOMA to SERRANO 500.0 kV No.1 & MIRALOMA to SERRANO 500.0 kV No.2
48.	MIRALOMA to SERRANO 500.0 kV No.1 & MIRALOME to OLINDA 230.0 kV No.1
49.	MIRALOMW to WALNUT 230.0 kV No.1 & OLINDA to WALNUT 230.0 kV No.1
50.	MIRALOMW to WALNUT 230.0 kV No.1 & MIRALOME to OLINDA 230.0 kV No.1
51.	MOORPARK to ORMOND 230.0 kV No.1 & MOORPARK to ORMOND 230.0 kV No.2
52.	MOORPARK to ORMOND 230.0 kV No.2 & MOORPARK to ORMOND 230.0 kV No.3
53.	MOORPARK to ORMOND 230.0 kV No.3 & MOORPARK to ORMOND 230.0 kV No.4
54.	OLINDA to WALNUT 230.0 kV No.1 & MIRALOME to OLINDA 230.0 kV No.1
55.	RIOHONDO to VINCENT 230.0 kV No.2 & VINCENT to RIOHONDO 230.0 kV No.1
56.	S.ONOFRE to SANTIAGO 230.0 kV No.1 & S.ONOFRE to SANTIAGO 230.0 kV No.2
57.	S.ONOFRE to SANTIAGO 230.0 kV No.2 & S.ONOFRE to SERRANO 230.0 kV No.1
58.	S.ONOFRE to SERRANO 230.0 kV No.1 & SERRANO to VALLEYSC 500.0 kV No.1
59.	S.ONOFRE to SERRANO 230.0 kV No.1 & VIEJOSC to CHINO 230.0 kV No.1
60.	S.ONOFRE to SERRANO 230.0 kV No.1 & VIEJOSC to S.ONOFRE 230.0 kV No.1
61.	SERRANO to VILLA PK 230.0 kV No.1 & SERRANO to VILLA PK 230.0 kV No.2
62.	SERRANO to VILLA PK 230.0 kV No.2 & LEWIS to SERRANO 230.0 kV No.2
63.	RANCHVST to MIRALOME 230.0 kV No.1 & RANCHVST to MIRALOME 230.0 kV No.2
64.	LEWIS to SERRANO 230.0 kV No.1 & LEWIS to SERRANO 230.0 kV No.2
65.	LEWIS to SERRANO 230.0 kV No.1 & LEWIS to VILLA PK 230.0 kV No.1

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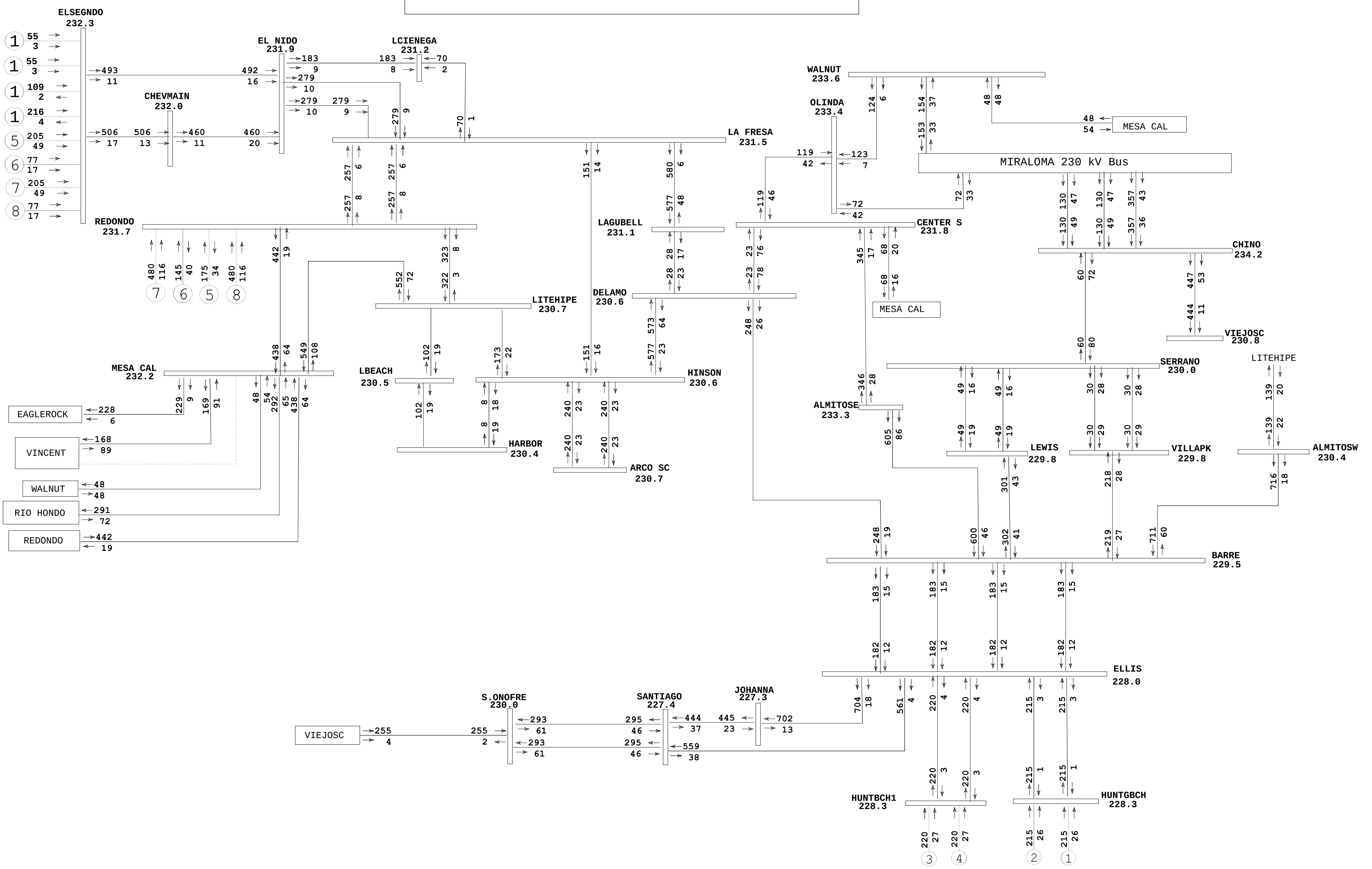

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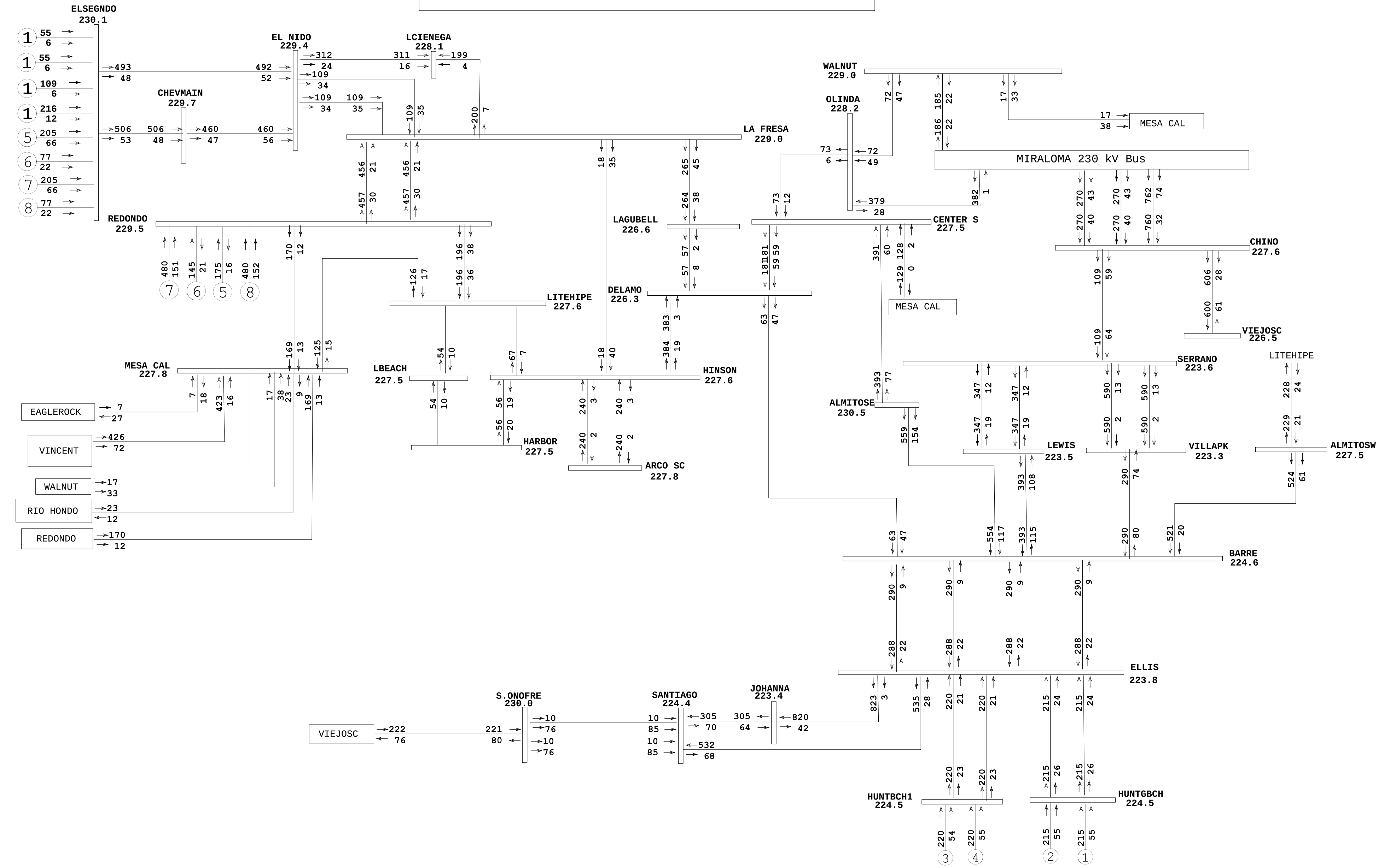
2016 Off Peak Base Case

SCE Metro Bulk System Study, Queue Cluster 5 Phase 2 Case

MW/MVAR

Rating = 1

SCE Metro Area 230 kV System



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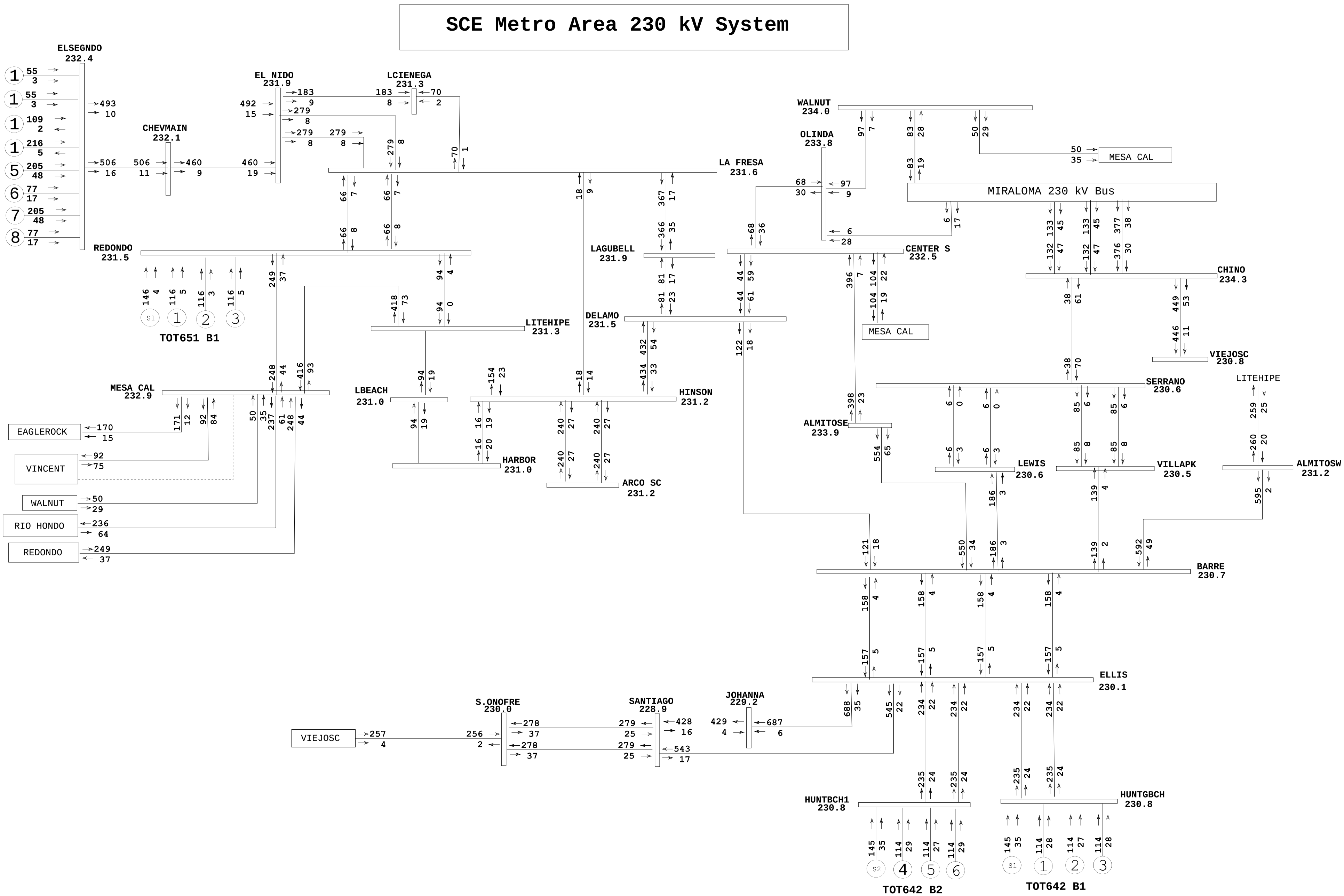
2016 Peak Base Case

SCE Metro Bulk System Study, Queue Cluster 5 Phase 2 Case

MW/MVAR

Rating = 1



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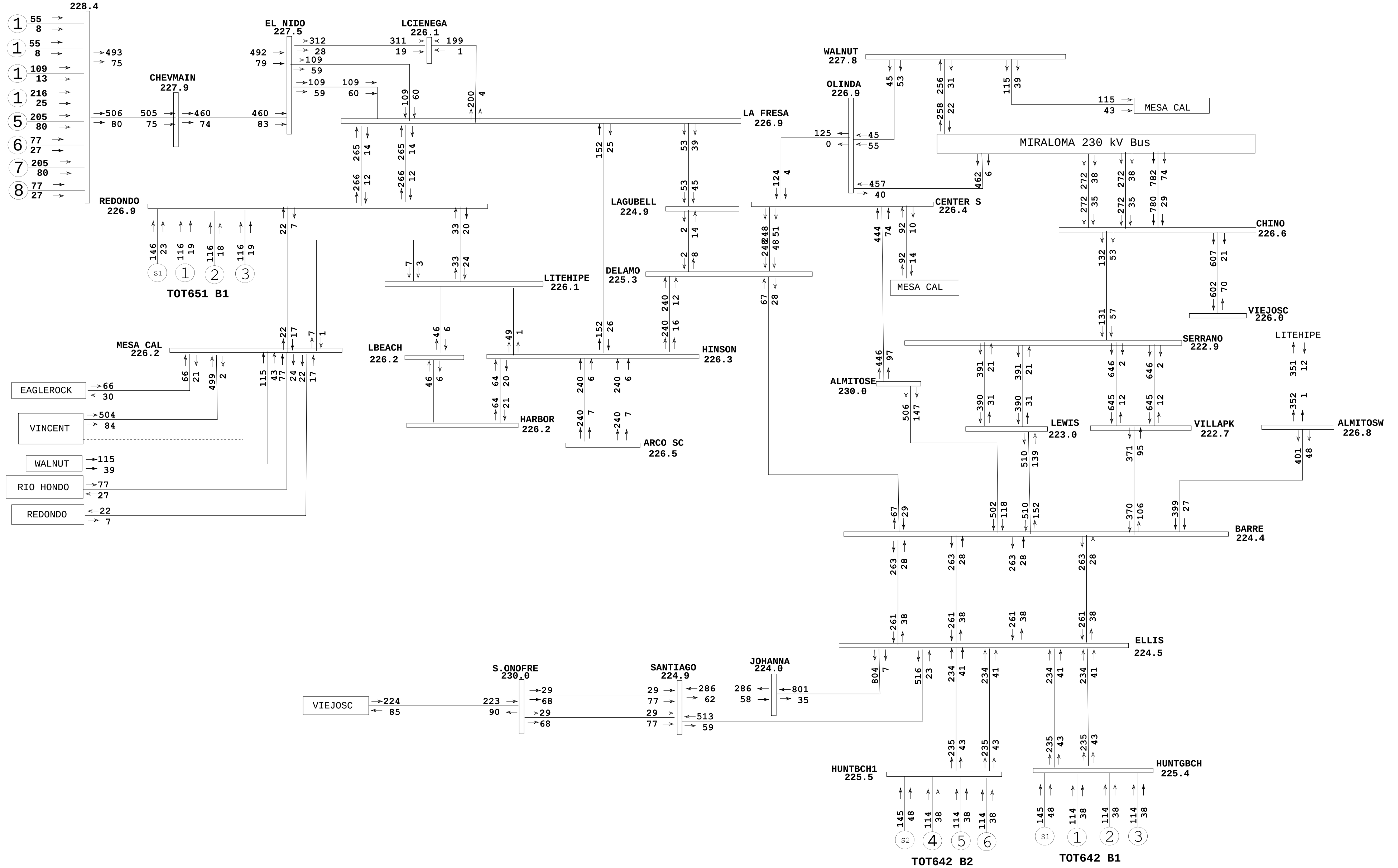

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2016 Peak Base Case

SCE Metro Bulk System Study, Queue Cluster 5 Phase 2 Case

MW/MVAR

Rating = 1

Appendix E

Cost and Construction Duration Estimates for Upgrades in Area

Table 1-1 Reliability Upgrades, Estimated Costs, and Estimated Time to Construct Time Summary

Upgrade	Estimated Cost x 1,000 Constant Dollars (2013)	Estimated Cost x 1,000 Constant Dollars (OD Year) Note 1	Estimated Time to Construct (Months) Note 2
Refer to Applicable Appendix A Report			

Table 1-2 Local Delivery Network Upgrades, Estimated Costs, and Estimated Time to Construct Time Summary

Upgrade	Estimated Cost x 1,000 Constant Dollars (2013)	Estimated Cost x 1,000 Constant Dollars (OD Year) Note 1	Estimated Time to Construct (Months) Note 2
None			

Table 1-3 Distribution Upgrades, Estimated Costs, and Estimated Time to Construct Time Summary

Upgrade	Estimated Cost x 1,000 Constant Dollars (2013)	Estimated Cost x 1,000 Constant Dollars (OD Year) Note 1	Estimated Time to Construct (Months) Note 2
None			

Note 1: The escalation factors to convert the estimated cost (in 'constant' 2013 dollars) to the estimated O.D. are found in the posted SCE 2013 Per Unit Cost Guide on the CAISO website:
http://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx

Note 2: The Estimated Time to Construct (duration in months) is the schedule for the PTO to complete final engineering, design, procurement, licensing, and construction, etc., and other activities needed to construct and bring the facilities into service. Such activities are from the execution of the Generator Interconnection Agreements, and receipt of: all required information, funding, and written authorization to proceed from the IC, as will be specified in the Generator Interconnection Agreement, to commence work. The estimated schedule does not take into account unanticipated delays or difficulties securing necessary permits, licenses or other approvals; construction difficulties or potential delays in the project implementation process; or unanticipated delays or difficulties in obtaining and receiving necessary clearances for interconnection of the project to the transmission system.

Note 3: The estimated licensing cost and construction durations applied to this project are based on the project scope details presented in this study. These estimates are subject to change as project specific environmental and real estate elements are further defined. Upon execution of the Generator Interconnection Agreement, additional evaluation including, but not limited to, preliminary engineering, environmental surveys, and property right checks may cause licensing cost and/or construction duration to be updated.

Note 4: Distribution upgrades are not identified in the ISO Tariff, and are not reimbursable. Allocated costs may change if all projects responsible for these upgrades do not execute Generator Interconnection Agreements.

Note 5: Interconnection Facilities costs are not reimbursable.

Note 6: Each Upgrade category may contain multiple work element construction durations. The longest construction duration is shown under the Estimated Time to Construct.

Note 7: SCE's Phase II cost estimating is done in 'constant' dollars 2013 and then escalated to the estimated O.D.year. For the QC5 study, the estimated O.D. is derived by assuming the duration of the work element will begin in June 2014, which is the CAISO tariff scheduled completion date of the QC5 Phase II study plus 120 days for the interconnection agreement signing period and submittal of required funds by the IC. For instance, if a work element is estimated to take a total of 24 months (final engineering, design, procurement, licensing and construction), then the estimated O.D. would be June 2016. If an IC's requested O.D.(in- service) is beyond the estimated O.D. of a work element, the IC's requested O.D. is used. However, should the Generator Interconnection Agreement not be executed, or the necessary information, funding, and written authorization to proceed is not provided by the IC in time for the Participating TO to perform the work within these time frames, the information provided in Table D.1 may be subject to change.

QUEUE CLUSTER 5 PHASE 2 TRANSIENT STABILITY

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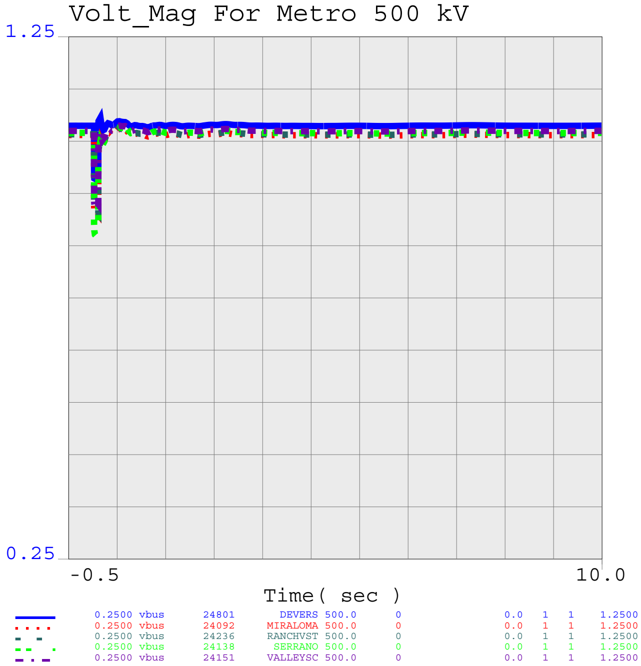
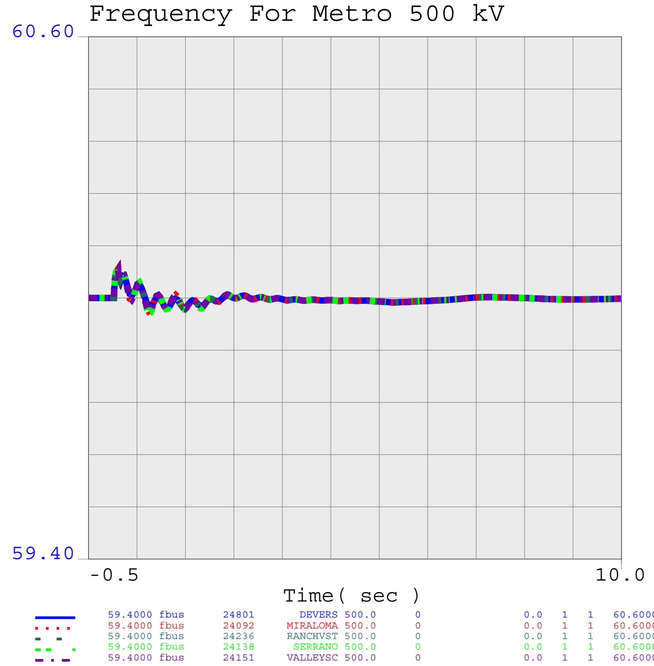
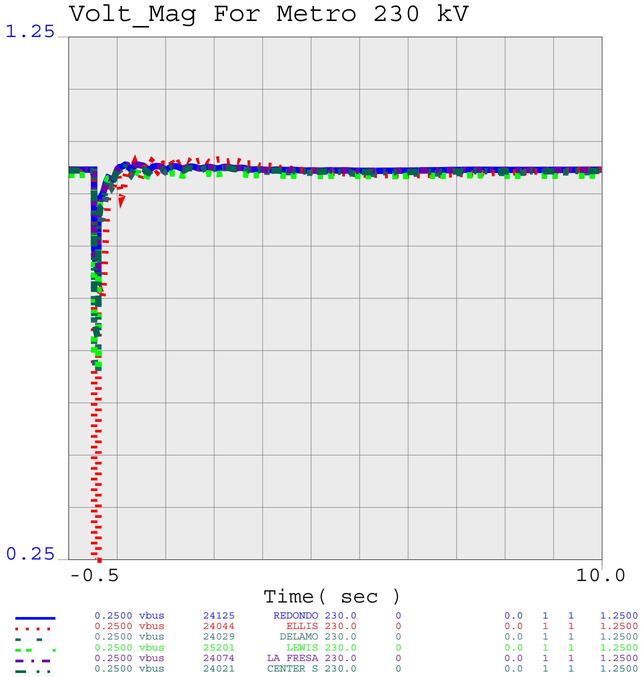


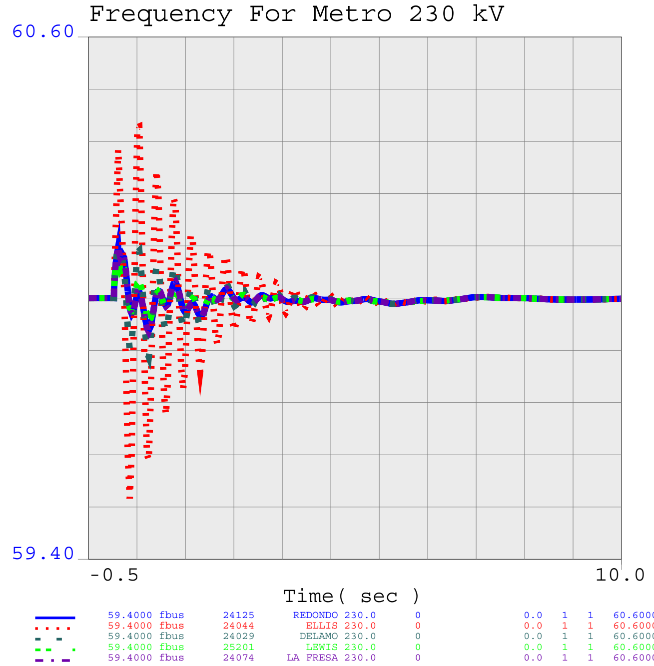
Frequency For Metro 500 kV



Volt_Mag For Metro 230 kV



Frequency For Metro 230 kV



QC5 METRO AREA
Heavy Spring Conditions

Page 1

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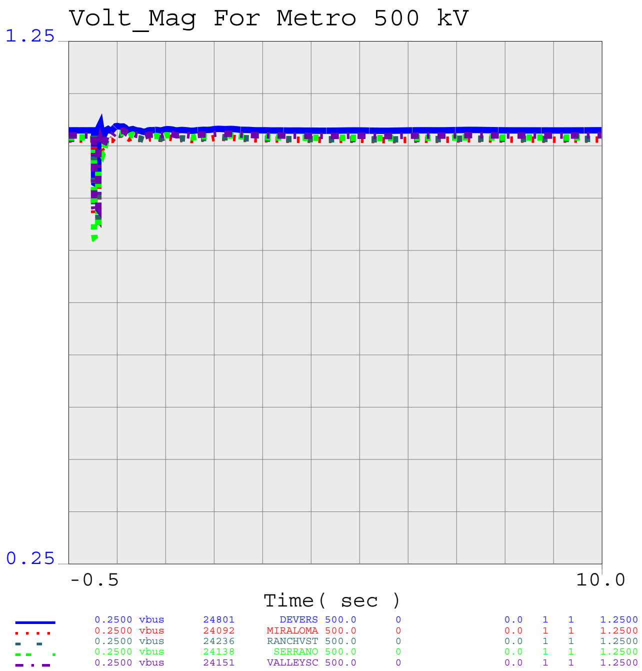

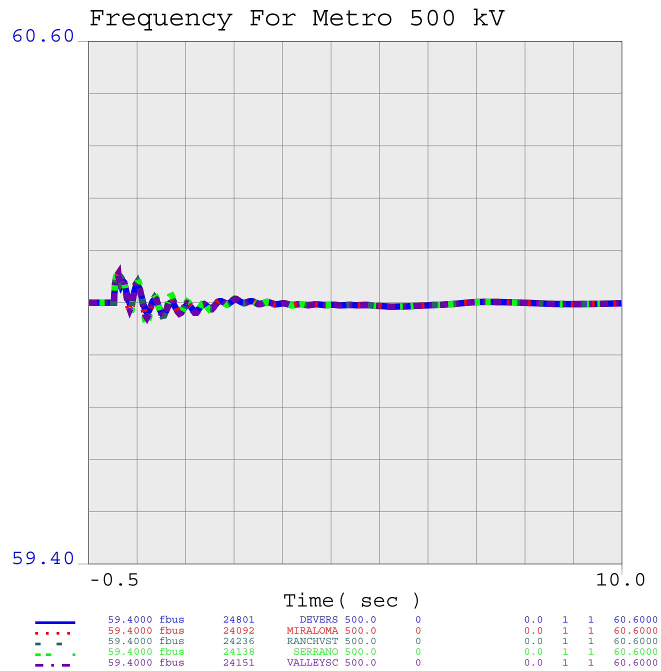

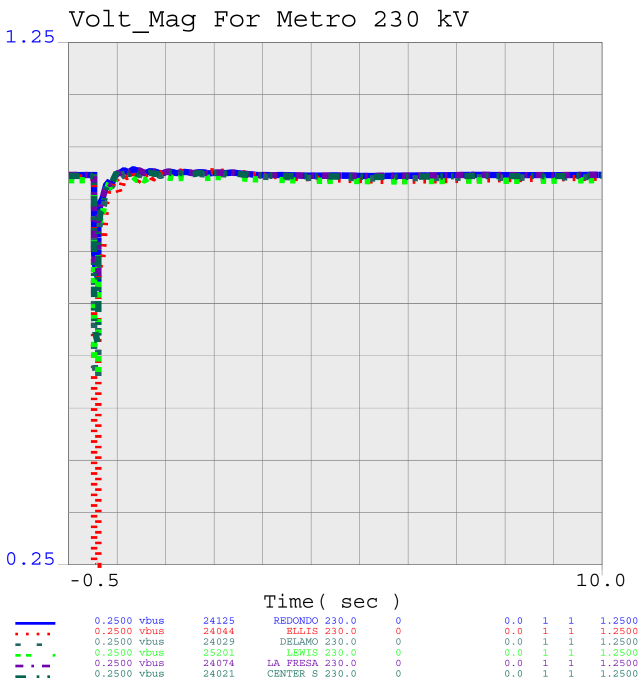

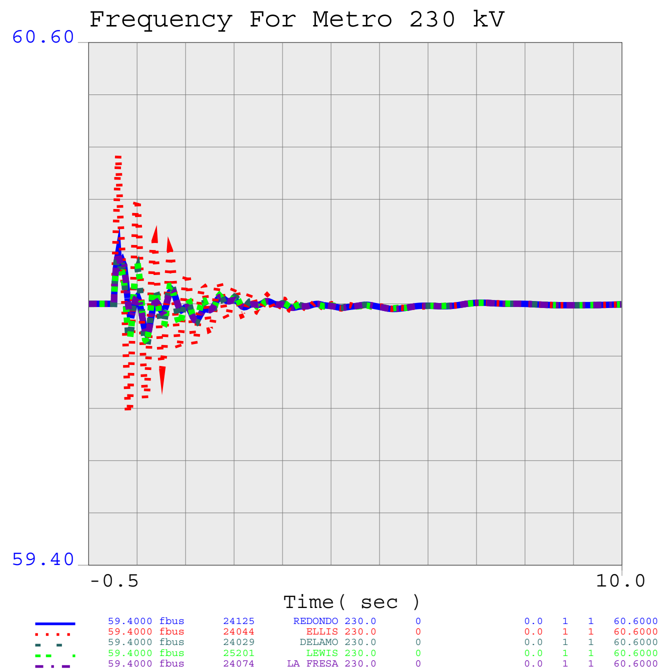

QC5 METRO AREA
Heavy Spring Conditions

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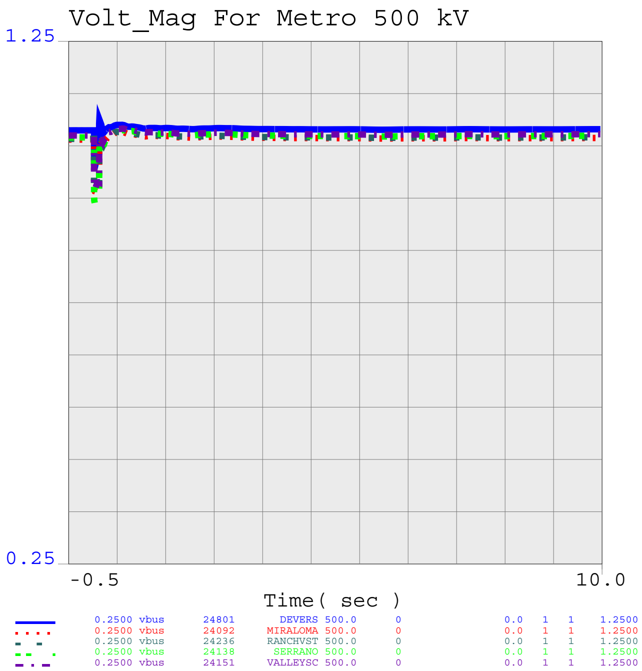

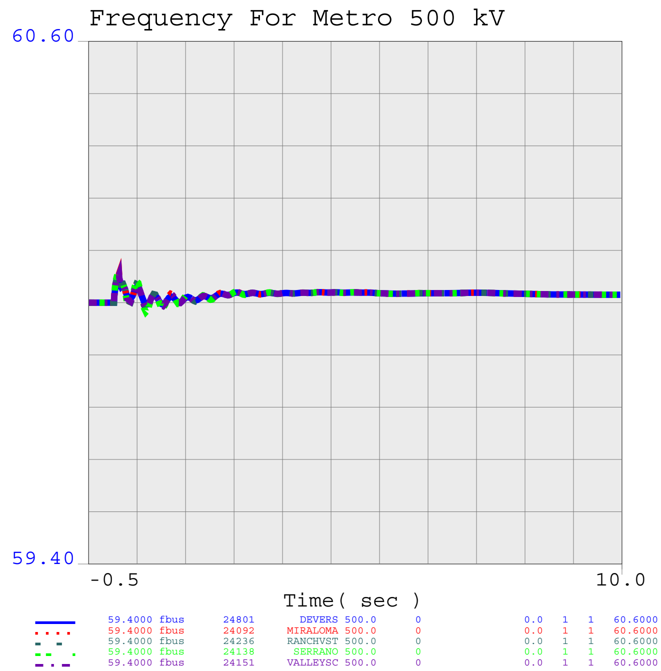

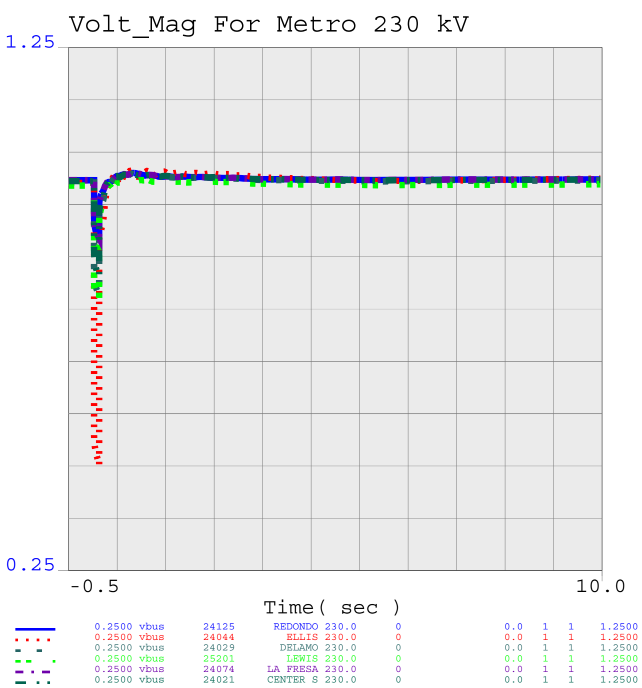

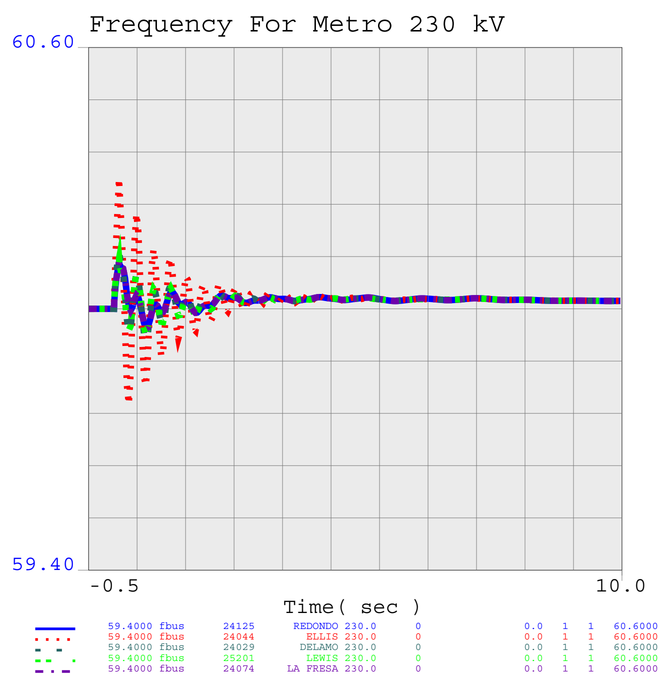

QC5 METRO AREA
Heavy Spring Conditions

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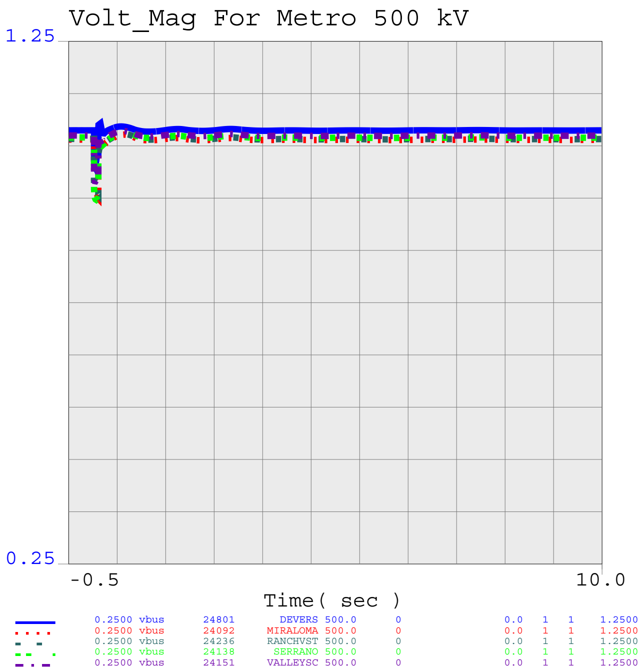

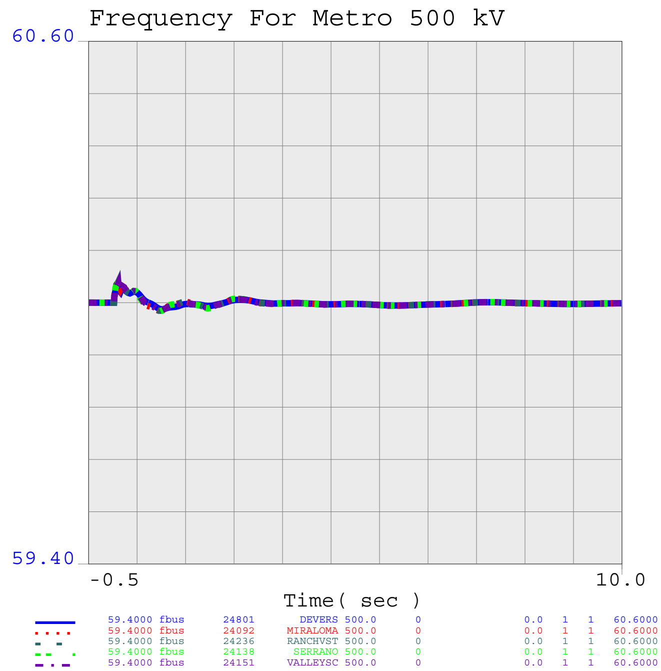

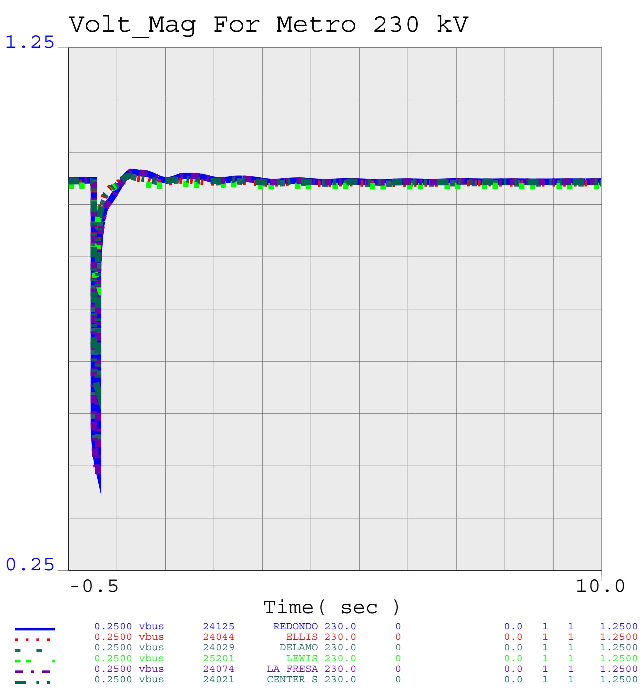

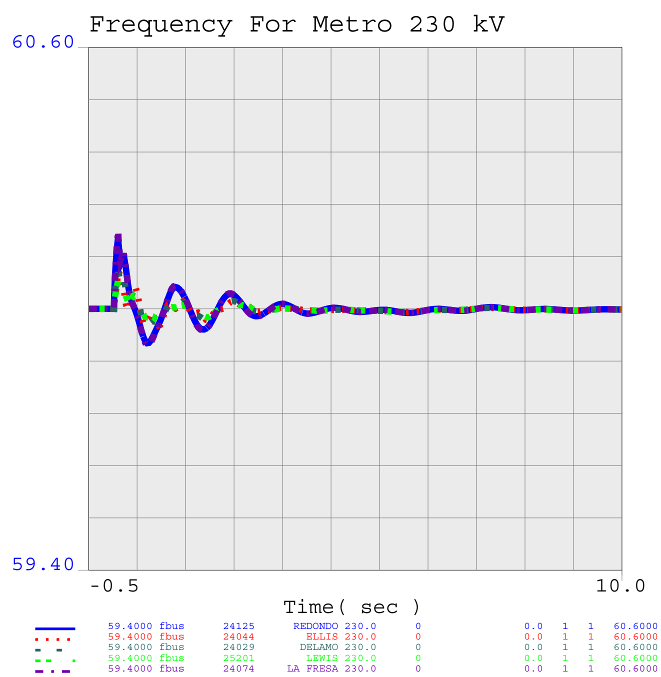

QC5 METRO AREA
Heavy Spring Conditions

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QUEUE CLUSTER 5 PHASE 2 TRANSIENT STABILITY

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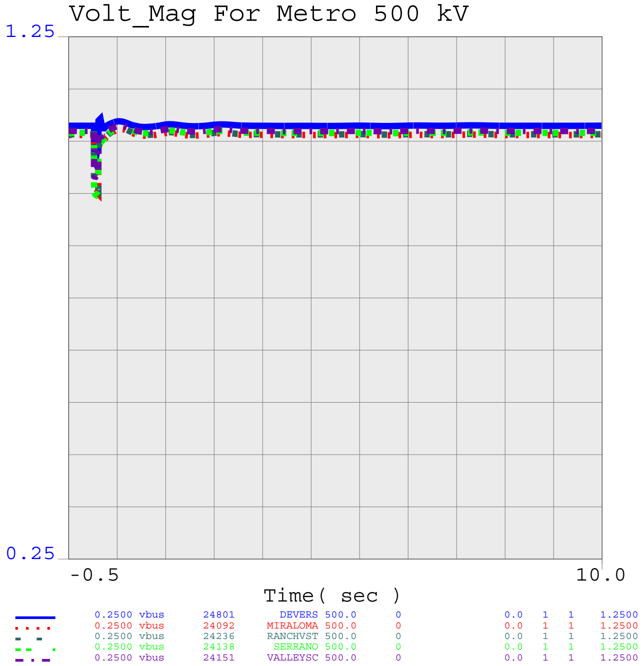
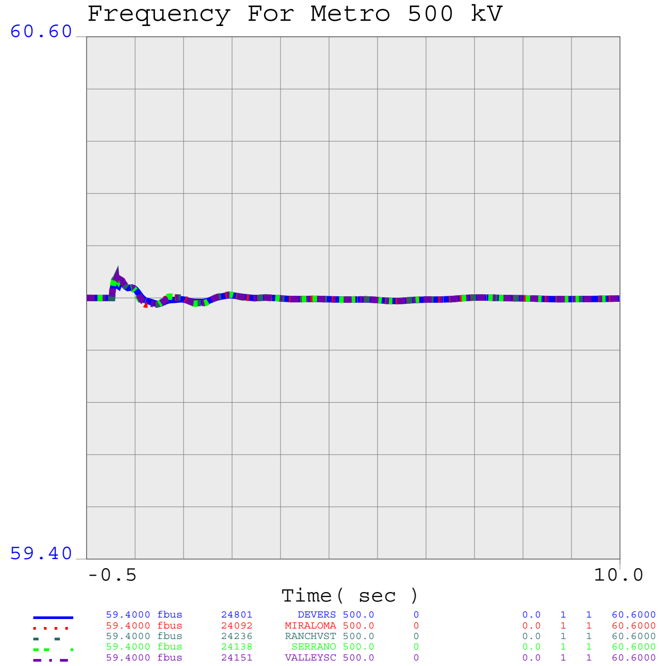
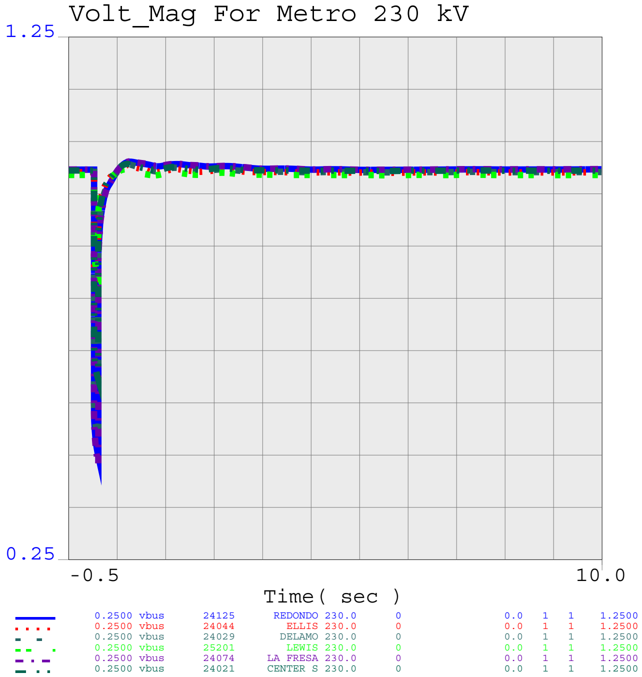


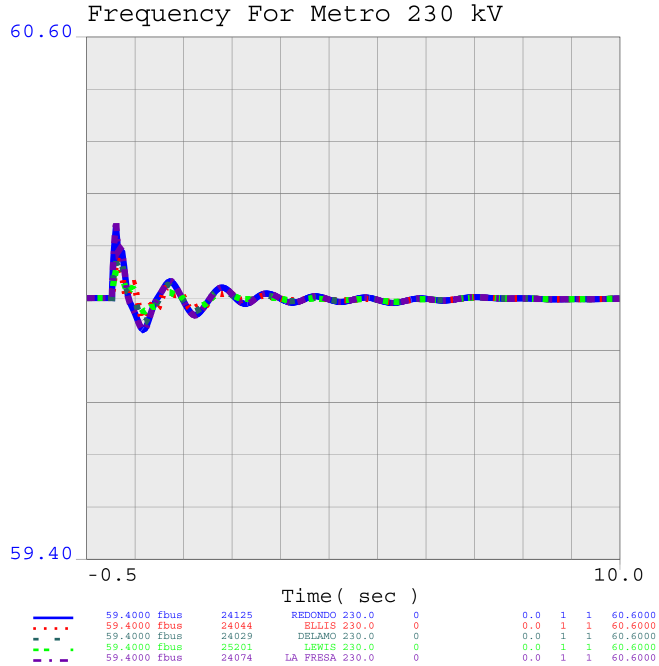
Frequency For Metro 500 kV



Volt_Mag For Metro 230 kV



Frequency For Metro 230 kV



QC5 METRO AREA
Heavy Spring Conditions

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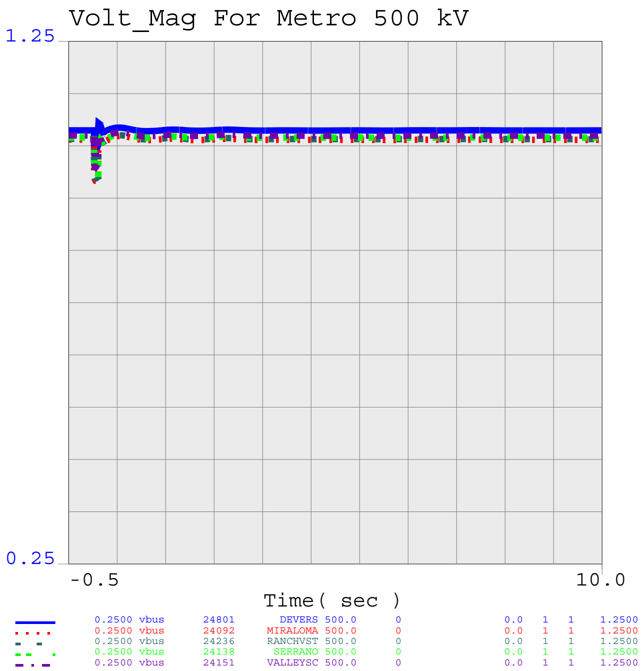
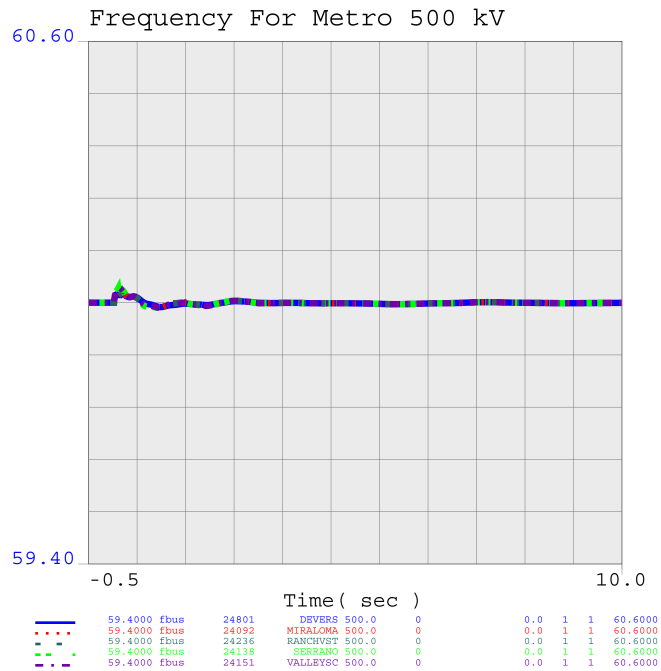
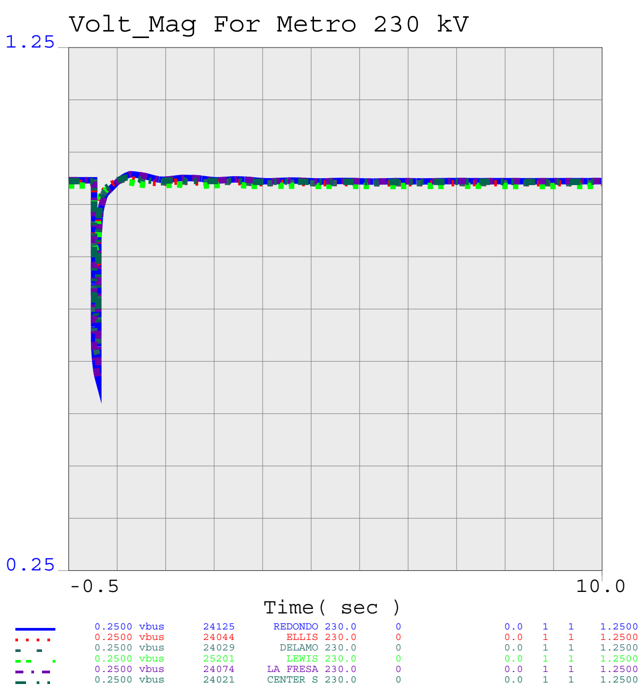
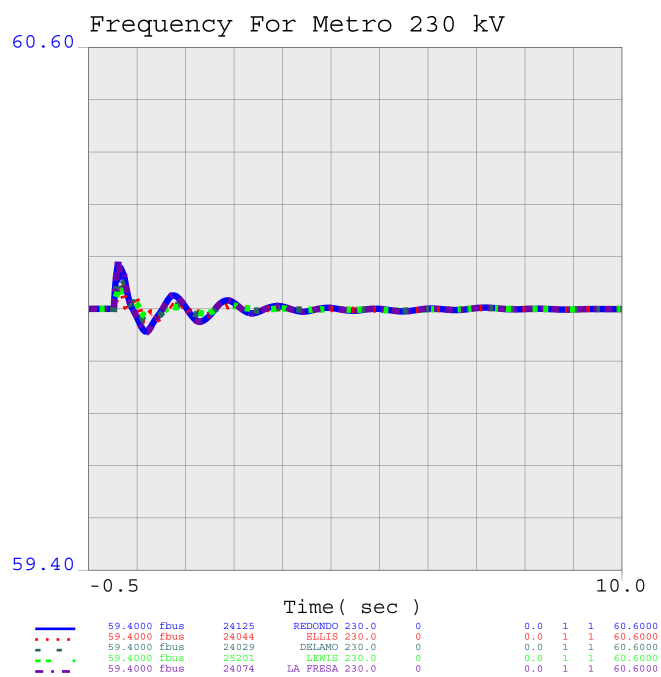
QUEUE CLUSTER 5 PHASE 2 TRANSIENT STABILITY









QC5 METRO AREA
Heavy Spring Conditions

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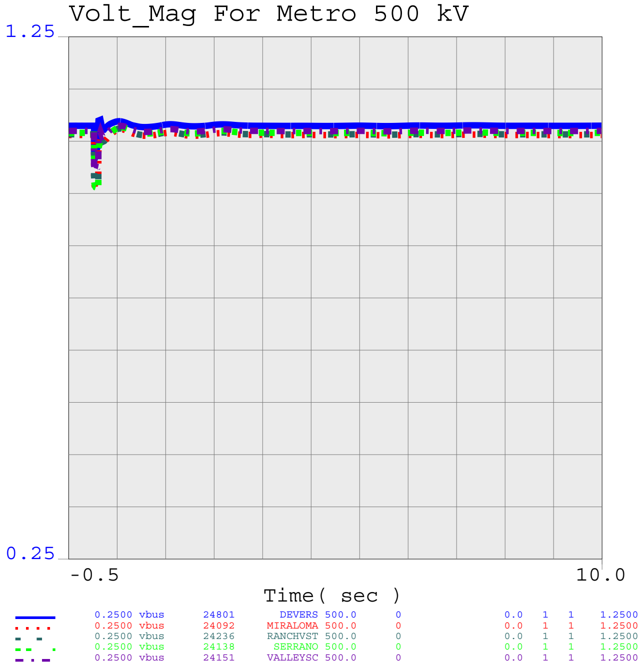
QUEUE CLUSTER 5 PHASE 2 TRANSIENT STABILITY

Volt_Mag For Metro 500 kV



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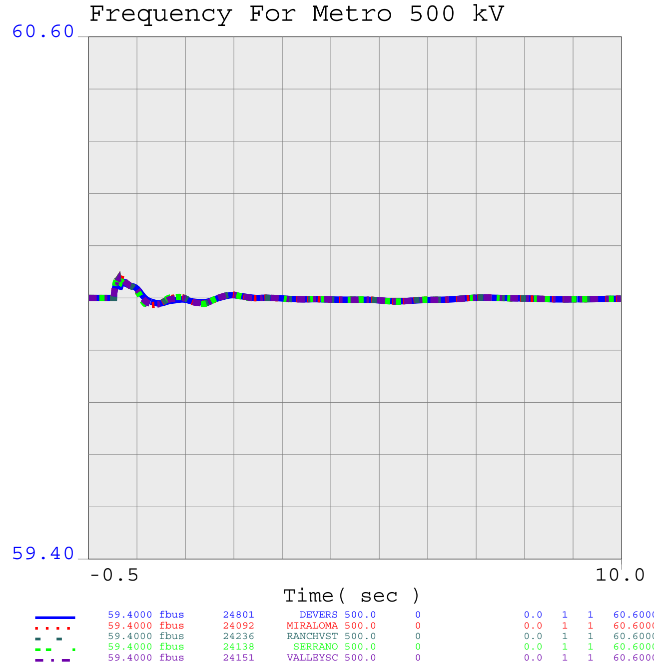

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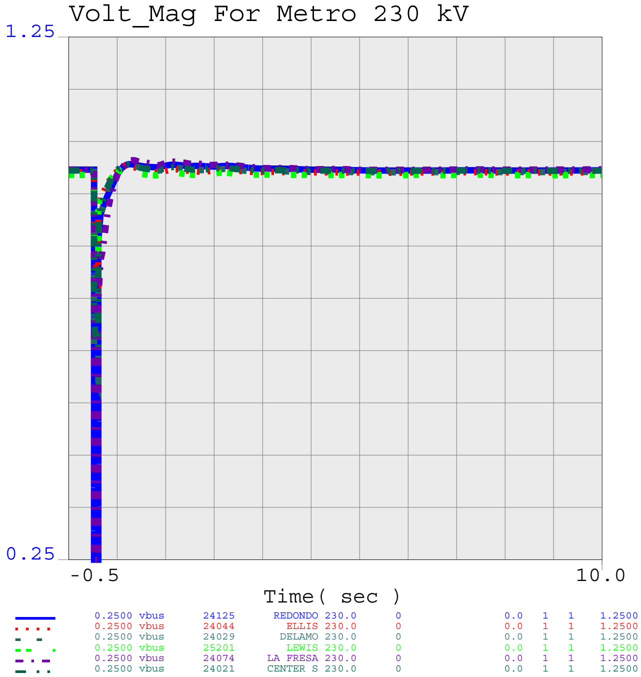
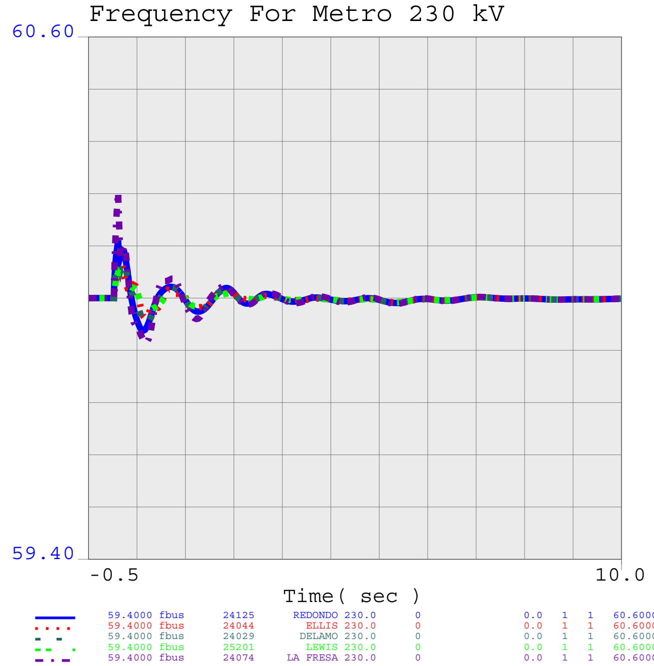


Frequency For Metro 230 kV



QC5 METRO AREA
Heavy Spring Conditions

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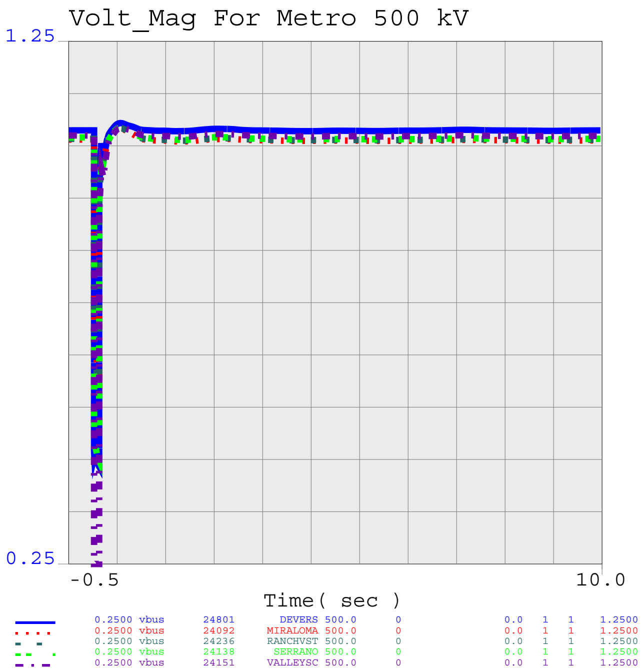

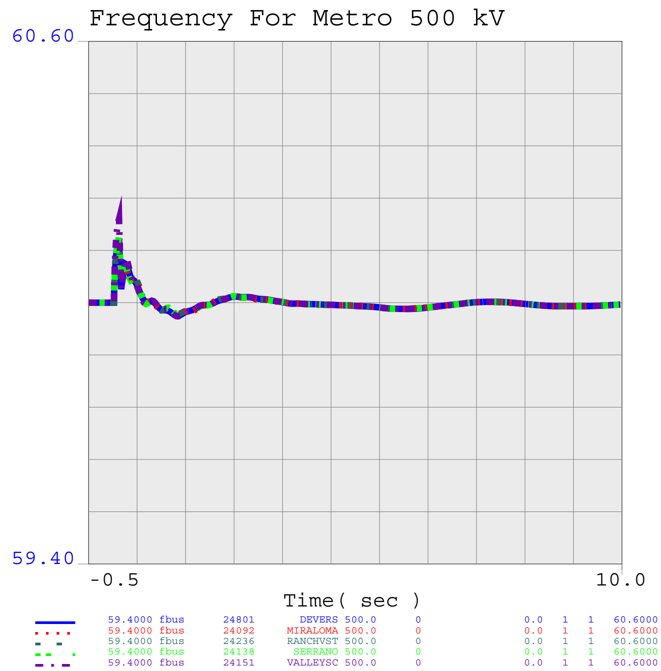

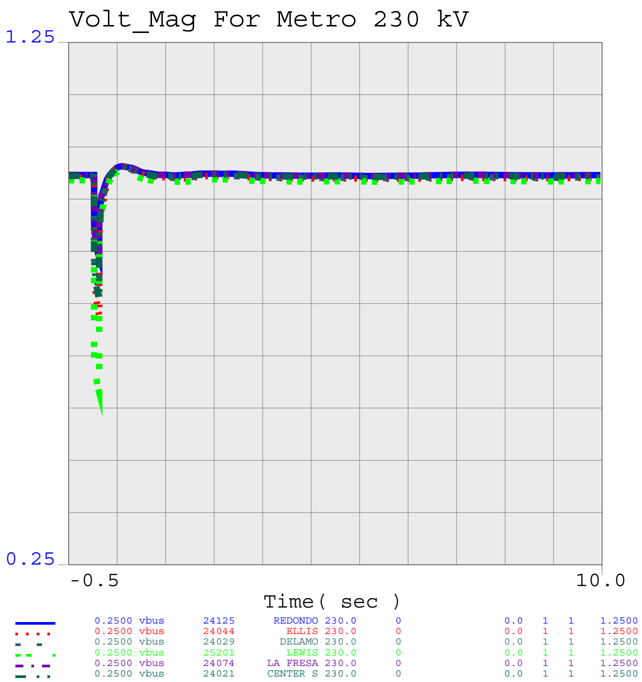

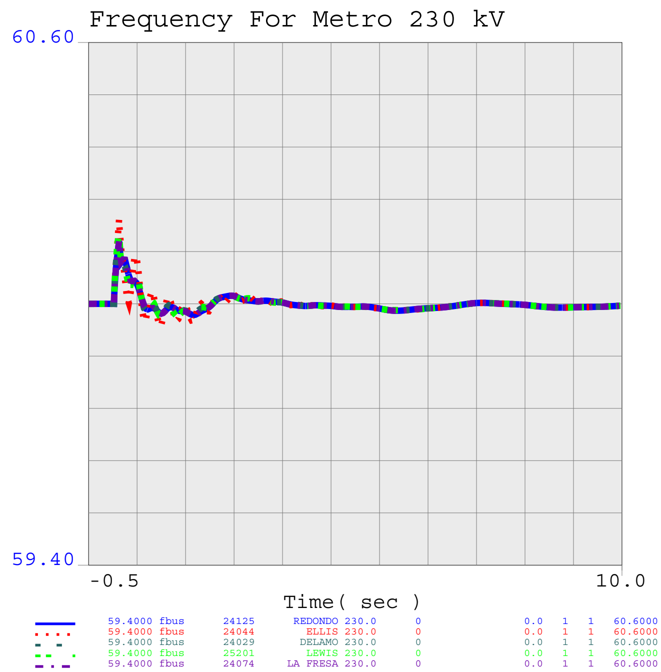

QC5 METRO AREA
Heavy Spring Conditions

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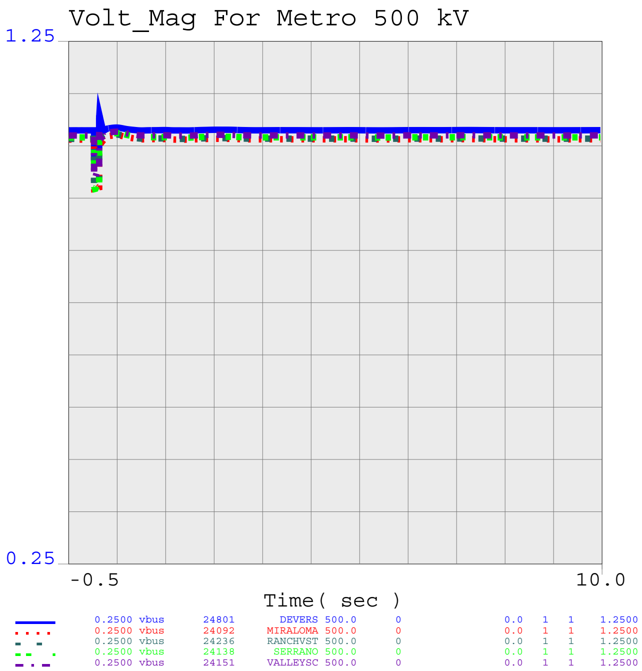

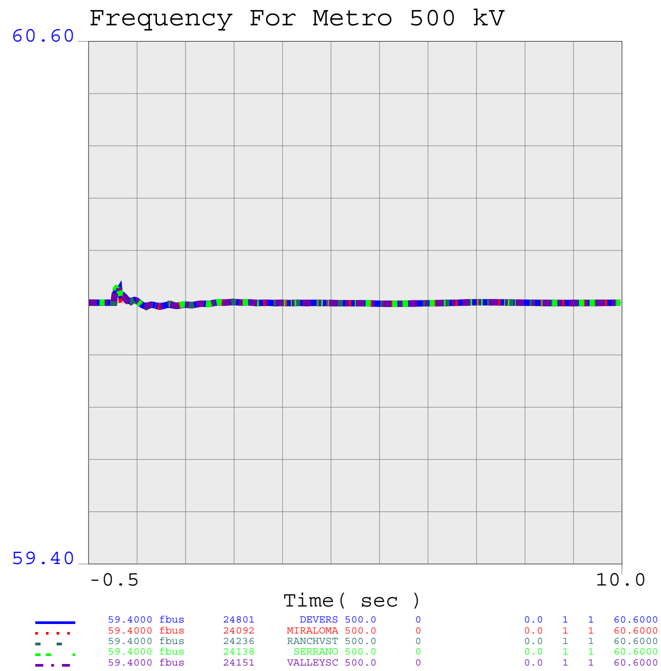

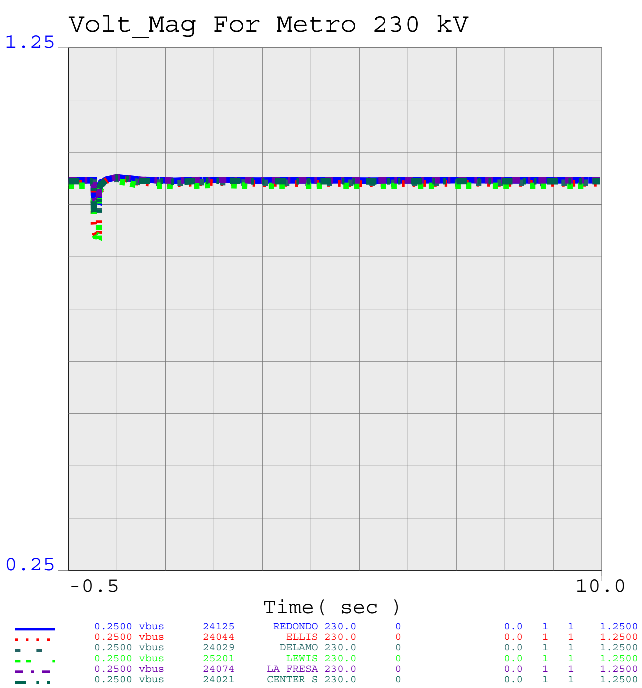

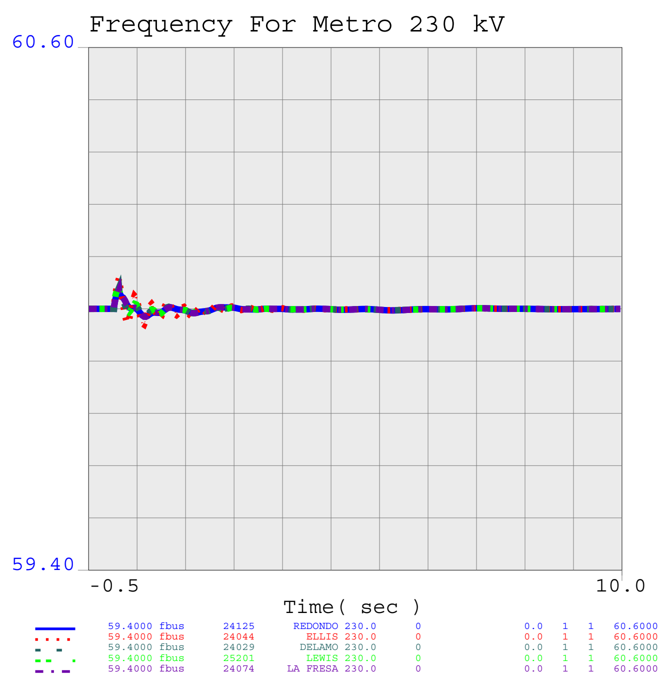

QC5 METRO AREA
Heavy Spring Conditions

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QC5 Phase II - Appendix G

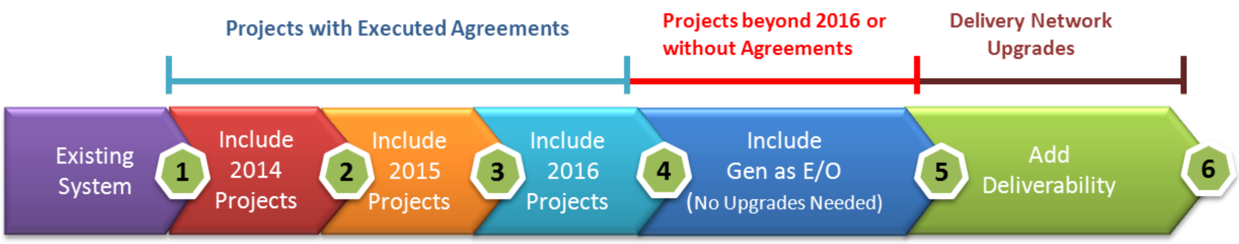
Generation Sequencing Implementation (GSI) Short Circuit Duty Evaluation Discussion

Table of Contents

A. GSI Short Circuit Duty Study Methodology

The GSI short-circuit duty studies were performed to identify timing of need for short-circuit duty mitigations. The GSI study considered six different scenarios as shown below in Figure H.2.1. These scenarios were selected as the most appropriate GSI study conditions.

Figure H.2.1 – Short Circuit Duty GSI Study



1. Projects with Interconnection Agreements

Three-phase (3PH) and single-line-to-ground (SLG) faults were simulated for the existing system condition to establish the starting base line conditions. Generation projects with an active Interconnection Agreement (LGIA, SGIA, GIA or Letter Agreement) filed at FERC were added for years 2013-4, 2015 and 2016 based on dates provided for in the Interconnection Agreement and as modified by the project execution team, if appropriate. In addition, transmission upgrades already licensed and permitted which are under construction or scheduled to be in-service by the end of 2016 were included into the 2013-4, 2015, and 2016 GSI studies. The list of new generation projects with executed agreements are summarized below in Table H.2.1, Table H.2.2 and Table H.2.3 for years 2013-4, 2015, and 2016 respectively and the list of transmission upgrades scheduled to be in-service by the end of 2016 are summarized below in Table H.2.4.

Table H.2.1
Generation Projects with Executed Agreement Expected to be In-Service in End of 2013-4

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Basin Area				
7	TOT041	10/06/00	El Segundo 230 kV	564
WDAT	WDT428	01/29/10	Kimball (Chino 66 kV System)	1.5
Eastern Area: Bulk				
146	TOT198	11/16/06	Red Bluff 220 kV	250
147	TOT199	11/16/06	Red Bluff 220 kV	300
193	TOT223	11/16/06	Red Bluff 220kV	250[1]
Eastern Area: Devers-Mirage 115 kV System				
WDAT	WDT042	01/07/00	Devers-Banning-Windpark 115 kV line	40
WDAT	WDT334	06/09/09	Hi Desert 33 kV	18.5
WDAT	WDT322	10/3/08	Purewater 115kV (Out of Vista 115kV)	22
WDAT	WDT884ISP	1/24/12	Minotaur 12 kV (Out of San Bernardino 66 kV)	5
East-of-Lugo: Eldorado/Ivanpah				
131	TOT180	09/25/06	Ivanpah 115 kV	133
162	TOT210	01/05/07	Ivanpah 115 kV	126
233	TOT242	06/27/07	Ivanpah 115 kV	133
Lugo Hub				
WDAT	WDT323	12/16/08	Cottonwood 33 kV	20
WDAT	WDT372	08/25/09	Victor 33 kV	20
WDAT	WDT409	12/09/09	Cottonwood 33 kV	10
WDAT	WDT421	01/25/10	Cottonwood 33 kV	20
WDAT	WDT508	01/25/10	Apple Valley 12 kV	0.98
WDAT	WDT648	09/13/2010	Victor 12 kV	2
WDAT	WDT649	09/13/2010	Victor 12 kV	5
North of Kramer				
125	TOT175	08/22/06	Sandlot 220 kV (formerly Water Valley)	250
Northern Area: Bulk				
119	TOT173	08/08/06	Windhub 220 kV	228[2]
407	TOT340	5/30/08	Whirlwind 220 kV	172[3]
408	TOT341	5/30/08	Whirlwind 220 kV	182[4]
412	TOT345	07/31/08	Whirlwind 220 kV	110[5]
602	TOT455	02/01/10	Whirlwind 220 kV	60[6]
Northern Area: Antelope-Bailey 66 kV System				
522A	TOT416	8/1/09	Rosamond 66 kV	20
522B	TOT417	8/19/09	Rosamond 66 kV	20
651A	TOT508	2/1/2010	Antelope 66 kV	20
653H	TOT516	2/1/2010	Antelope 66 kV	10
660	TOT522	2/1/2010	Antelope 66 kV	20
WDAT	WDT628	09/07/10	Rosamond 12 kV	5
WDAT	WDT638	09/07/10	Del Sur 12 kV	5
WDAT	WDT639	09/07/10	Del Sur 12 kV	5
WDAT	WDT640	09/07/10	Little Rock	5
WDAT	WDT641	09/07/10	Little Rock	5

[1] This figure reflects partial interconnection of 250 MW of the 500 MW project in 2013-4.
[2] This figure reflects partial interconnection of 228 MW of the 500 MW Project in 2013-4.
[3] This figure reflects partial interconnection of 172 MW of the 310 MW Project in 2013-4.
[4] This figure reflects partial interconnection of 182 MW of the 276 MW Project in 2013-4.
[5] This figure reflects installing the remaining 113 MW of the 250 MW Project in 2013-4.
[6] This figure reflects installing an additional 60 MW of the 150 MW Project increasing installed amount to 110 MW in 2013-4.

Table H.2.1
Generation Projects with Executed Agreement Expected to be In-Service in End of 2013-4 (Continued)

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Northern Area: Windhub 66 kV System				
WDAT	WDT368	08/20/09	Goldtown 12 kV	5
WDAT	WDT402	11/25/09	Goldtown 12 kV	10
856	TOT591	3/31/11	Monolith 66 kV	8
Northern Area: Saugus/Ventura				
WDAT	WDT273	03/26/08	Saugus 66 kV System	20
WDAT	WDT661ISP	06/09/11	Estero 16 kV	11.2

Table H.2.2
Generation Projects with Executed Agreement Expected to be In-Service in End 2015

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Eastern Area: Bulk				
365	TOT321	05/12/08	Red Bluff 220 kV	250[7]
193	TOT223	07/31/08	Colorado River 230 kV	250[8]
East-of-Lugo: Eldorado/Ivanpah				
467	TOT381	07/31/08	Primm 220 kV	230
502	TOT405	07/31/09	Primm 220 kV	20
503	TOT404	07/31/09	Merchant 220 kV	63
East-of-Lugo: Jasper/Pisgah				
135	TOT183	10/10/06	Jasper 220 kV	60
Lugo Hub				
WDAT	WDT491	01/25/10	Victor 33 kV	20
North of Kramer				
125	TOT175	08/22/06	Water Valley 230 kV	250
Northern Area: Bulk				
20	TOT108	09/04/03	Whirlwind 220 kV	111[9]
73	TOT148	06/27/05	Whirlwind 230 kV	110[10]
132	TOT179	09/27/06	Highwind 230 kV	137[11]
188	TOT219	05/30/08	Windhub 220 kV	200
407	TOT340	05/30/08	Whirlwind 220 kV	138[12]
408	TOT341	05/30/08	Whirlwind 230 kV	94[13]
537A	TOT430	11/23/09	Highwind 220 kV	19.5
602	TOT455	02/01/10	Whirlwind 220 kV	40[14]

[7] This figure reflects partial interconnection of 250 MW of the 500 MW Project in 2015.
[8] This figure reflects installing the remaining 250 MW of the 500 MW Project in 2015.
[9] This figure reflects installing the remaining 111 MW of the 300 MW Project in 2015.
[10] This figure reflects installing the remaining 110 MW of the 250 MW Project in 2015.
[11] This figure reflects installing the remaining 137 MW of the 297 MW Project in 2015.
[12] This figure reflects installing the remaining of 138 MW of the 310 MW Project in 2015.
[13] This figure reflects installing the remaining of 94 MW of the 276 MW Project in 2015.
[14] This figure reflects installing the remaining of 40 MW of the 150 MW Project in 2015.

Table H.2.3
Generation Projects with Executed Agreement Expected to be In-Service by End 2016

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Eastern Area: Bulk				
294	TOT276	01/16/08	Colorado River 115/33 kV	485
365	TOT321	05/12/08	Red Bluff 220 kV	250[15]
Eldorado/Ivanpah				
163	TOT211	07/31/08	Ivanpah 220 kV	300
North of Kramer				
142	TOT192	11/06/06	Kramer 220 kV	60
Northern Area: Bulk				
93	TOT161	03/01/06	Windhub 220 kV	58[16]
119	TOT173	08/08/06	Windhub 220 kV	180[17]

Table H.2.4
Transmission Upgrades with a Well Defined In-Service Date Prior to End of 2016

System Upgrade	OD
Basin Area	
Upgraded Chino-Mira Loma No.3 220 kV (TRTP Segment 8C) (Common 500 kV double-circuit replacing former Chino-Mira Loma No.1&2 220 kV)	2014
Eastern Area	
West-of-Devers Interim Line Reactors	2013
Colorado River Substation (DC-R) (With No.1 and No.2 500/220 kV Transformer Banks)	2013
New Colorado River - Red Bluff No.2 500 kV (DC-R/Red Bluff)	2013
El Casco 220/115 kV Sub-transmission (Roll portions of Devers 115 kV System to El Casco)	2013
Devers-Mirage No.2 and Coachella-Mirage 220 kV (Path 42) (Remove existing Devers-Coachella 220 kV)	2014
Devers-Red Bluff No.1, Colorado River-Red Bluff No.1 and Colorado River-Palo Verde 500 kV (DC-R) (Remove existing Devers-Palo Verde 500 kV)	2014
New Series Comp on Devers-Red Bluff No.1 and No.2 500 kV (DCR)	2014
New Devers-Valley No.2 500 kV (DC-R)	2014
East of Pisgah Area	
Magnolia-NSO 230 kV T/L Loop-in to Eldorado (Concurrent with Merchant two-line radial service to Eldorado)	2013
New SCE-Only Eldorado No. 5AA 500/220 kV Transformer Bank (Remove temporary connection to joint-owned Eldorado and connect to 500 kV via single AA-Bank. Also, modify Ivanpah SPS)	2015
Eldorado-Mohave & Eldorado-Moenkopi 500 kV Line Swap	2014
New Primm 230 kV Substation and Eldorado-Ivanpah No.2 230 kV T/L Loop-in	2015

[15] This figure reflects installing the remaining of 250 MW of the 500 MW Project in 2016.
[16] This figure reflects installing the remaining 58 MW of the 226 MW project in 2016.
[17] This figure reflects installing an additional 180 MW of the 516 MW Project increasing installed amount to 408 MW in 2014.

Table H.2.4
Transmission Upgrades with a Well Defined In-Service Date Prior to End of 2016
(Continued)

System Upgrade	OD
North of Lugo Area	
Jasper 220 kV Substation Looping exiting Lugo-Pisgah 220 kV No.1	2015
Lugo-Jasper (or Desert View) and Cool Water-Jasper (or Desert view) T/L	2015
Northern Area	
EKWRA - MOVE Sequence V-XI	2013
EKWRA - MOVE Sequence XII-XV	2014
Whirlwind No.3 500/220 kV (second AA-Bank) and AA-Bank SPS	2014
Vestal No.1&2 220/66 kV Transformer Bank Replacement	2013/14
Big Creek3-Rector No.2 and Springville-Rector 220 kV (SJXVL) (Remove existing Big Creek3-Springville 220 kV)	2014
Rio Hondo-Vincent No.2 Replacement (TRTP Segment 6 and Segment 7)	2014
Pardee-Vincent No.2 220 kV, Eagle Rock-Gould 220 kV, and Mesa-Vincent No.2 220 kV (TRTP Segment 11) (Remove existing Eagle-Rock-Pardee 220 kV)	2014
Saugus No.4 220/66 kV Transformer Bank	2015
Whirlwind No.4 500/220 kV (third AA-Bank) and AA-Bank SPS modification	2016
Mira Loma-Vincent 500 kV (TRTP Segment 6, Segment 7, and Segment 8)	2016

2. Projects with Executed Agreements but In-Service Date after 2016 and All Other Generation Projects Assumed To Be Interconnected as Energy Only

In order to provide a preview of additional circuit breaker upgrade or replacement requirements that could materialize as more and more generation projects are interconnected, the operational study considered the inclusion of all other generation projects. This includes both generation projects with executed agreements but in-service dates beyond 2016 and generation projects that do not yet have an executed agreement in place assuming they could be interconnected as Energy Only resource. These projects were added to the 2016 GSI study scenario together with already permitted transmission upgrades that will be in-service beyond 2016. While the interconnection customers may be requesting an earlier in-service dates, this study method will define all of the circuit breaker upgrades and/or replacements needed to interconnect every single generation project that can be interconnected as Energy Only. For those projects that requested Full Delivery status, impacts to short circuit duty associated with the Delivery Network Upgrades is covered by subsequent study scenarios.

The study did not take into account permitting timeframes associated with construction of the facilities needed to support the Energy Only interconnection and simply assumed such facilities would be in place. The objective of this GSI Study scenario is to identify locations where additional circuit breaker upgrade or replacement requirements could materialize as interconnection agreements are executed so that resource requirements could be identified in order to enable interconnection of any generation project. While some of these generation projects have articulated a desire for an earlier in-service date, there is no executed agreement in place committing to such interconnection timeframes. Consequently, the study performed grouped all of these projects together. The list of the generation projects and transmission upgrades modeled in this GSI study scenario are summarized below in Table H.2.5 and Table H.2.6 respectively.

Table H.2.5
Generation Project with Executed Agreements But In-Service Date After 2016 and All Other Generation Projects Assumed To Be Interconnected as Energy Only

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Basin Area				
383	TOT327	07/31/08	Arco-Hinson 230 kV	85
WDAT	WDT426	1/29/2010	Kimball (Chino 66 kV System)	2
WDAT	WDT427	1/29/2010	Soquel (Chino 66 kV System)	0.75
WDAT	WDT429	1/29/2010	Soquel (Chino 66 kV System)	1.5
WDAT	WDT463	4/7/2010	Upland 12 kV (Pauda 66 kV System)	1
WDAT	WDT464	4/7/2010	Milliken 12 kV (Mira Loma 66 kV System)	0.5
WDAT	WDT466	4/7/2010	Milliken 12 kV (Mira Loma 66 kV System)	0.5
WDAT	WDT471	4/7/2010	Cucamonga 12 kV (Padua 66 kV System)	0.75
WDAT	WDT473	4/7/2010	Cucamonga 12 kV (Padua 66 kV System)	1.75
WDAT	WDT475	4/7/2010	La Mirada 12 kV (Del Amo 66 kV System)	0.75
WDAT	WDT478	4/7/2010	Carson 12 kV (Lighthipe 66 kV System)	0.75
WDAT	WDT479	4/7/2010	Nogales 12 kV (Walnut 66 kV System)	0.75
WDAT	WDT482	4/8/2010	Carmenita 12 kV (Out of Del Amo 66 kV System)	1.33
WDAT	WDT483	4/8/2010	Carmenita 12 kV (Out of Del Amo 66 kV System)	1.25
WDAT	WDT484	4/8/2010	Carmenita 12 kV (Out of Del Amo 66 kV System)	1.5
WDAT	WDT485	4/8/2010	Carmenita 12 kV (Out of Del Amo 66 kV System)	1
WDAT	WDT486	4/8/2010	Carmenita 12 kV (Out of Del Amo 66 kV System)	1.75
WDAT	WDT589	5/24/2010	Laguna Bell 16 kV (Laguna Bell 66 kV System)	1
702	TOT560	3/31/2011	El Segundo 220 kV	435
WDAT	WDT934	3/30/2012	Etiwanda 12 kV (Out of Etiwanda 66 kV System)	0.63
939	TOT638	3/31/2012	Alamitos 220 kV	1903
893	TOT642	3/31/2012	Ellis 220 kV	939
941	TOT651	3/31/2012	Redondo Beach 220 kV	476
WDAT	WDT910	3/31/2012	Etiwanda 12 kV (Out of Etiwanda 66 kV System)	1.5
Eastern Area: Bulk				
17	TOT079	04/22/03	Colorado River 500 kV	520
72	TOT132	06/16/05	Alberhill 500 kV (Previously Lee Lake)	500
138	TOT185	10/23/06	West-of-Devers Transmission	150

Table H.2.5
Generation Project with Executed Agreements But In-Service Date After 2016 and All Other Generation Projects Assumed To Be Interconnected as Energy Only (Continued)

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Eastern Area: Bulk (Continued)				
219	TOT237	05/23/07	Colorado River 500 kV	50
421	TOT349	05/30/08	Red Bluff 220 kV	50
576	TOT446	02/01/10	Colorado River 220 kV	485

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
588	TOT453	02/01/10	Red Bluff 220 kV	200
643AE	TOT486	07/31/10	Red Bluff 220 kV	150
797	TOT566	03/31/11	Red Bluff 220kV	0.5
798	TOT528	03/31/11	Colorado River 220kV	221
Eastern Area: Blythe				
WDAT	WDT357	08/17/09	McCoy 33 kV (Out of Blythe 33 kV)	20
Eastern Area: Devers-Mirage 115 kV System				
WDAT	WDT011	03/23/98	Renwind 115/12 kV	9
1	TOT022	09/30/98	Devers-Garnet 115 kV	16.5
WDAT	WDT1056 (formerlyTOT120)	12/14/04	Devers 115 kV	100.5
WDAT	WDT401	10/08/08	Venwind 115 kV	20
WDAT	WDT400	02/01/10	Pan Aero 115 kV	30
WDAT	WDT440	04/05/10	Garnet 33 kV	5
WDAT	WDT530	05/04/10	Hi Desert 115/33 kV	20
WDAT	WDT535	05/07/10	Garnet 33 kV	11
632AA	TOT476	02/01/10	Devers-Farrell 115 kV Line	10
Eastern Area: San Bernardino 66 kV System				
WDAT	WDT179	03/18/05	Colton-Bloomington 66 kV Line	49.9
WDAT	WDT492	03/31/11	Cardiff 12 kV	2
WDAT	WDT590	03/31/11	Limonite 33 kV (Out of Vista 115 kV)	8.18
WDAT	WDT689	03/31/11	Timoteo 12 kV	1.5
WDAT	WDT900	03/31/12	Maraschino 12 kV	10
Eastern Area: Valley 115 kV System				
WDAT	WDT182	05/06/05	Valley 115 kV	507.5
WDAT	WDT609	03/31/11	Mayberry 115/12 kV	10
WDAT	WDT668	03/31/11	Nelson 115/33 kV	26
WDAT	WDT787	03/31/11	Stetson 115/12 kV	9
WDAT	WDT786	03/31/11	Nelson 115/33 kV	20

Table H.2.5
Generation Project with Executed Agreements But In-Service Date After 2016 and All Other Generation Projects Assumed To Be Interconnected as Energy Only (Continued)

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Eldorado/Ivanpah/VEA/Pisgah/Jasper				
205	TOT226	04/20/07	SCE-owned new Eldorado 220 kV	5
240	TOT250	07/12/07	Pisgah 230 kV	400
241	TOT245	07/12/07	Pisgah 230 kV	400
552	TOT438	02/01/10	Jasper 220 kV	60
593	TOT448	02/01/10	Mohave 500 kV	310

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
855	TOT581	03/31/11	Merchant 220 kV (non SCE-owned)	150
908	TOT655	03/31/12	Crazy Eyes 220 kV (VEA System)	210
Lugo Hub				
589	TOT452	02/01/10	Victor 115 kV	60
WDAT	WDT406	02/24/10	Cottonwood 33 kV	3
WDAT	WDT618	09/07/10	Victor 115/12 kV Distribution	2
WDAT	WDT642	09/07/10	Cottonwood-Savage 115 kV	20
WDAT	WDT646	09/09/10	Victor 12 kV	5
WDAT	WDT647	09/09/10	Victor 33 kV	5
WDAT	WDT650	09/07/10	Victor 12 kV	5
WDAT	WDT651	09/09/10	Victor 33 kV	2
WDAT	WDT617	09/09/10	Victor 33 kV	2
WDAT	WDT788	03/31/11	Victor 33 kV	10
WDAT	WDT791	03/31/11	Victor 33 kV	20
WDAT	WDT854	06/01/11	Aqueduct 12 kV	1.5
WDAT	WDT901	03/31/12	Savage 12 kV	5
WDAT	WDT925	03/31/12	Victor 33 kV	7
North of Kramer				
WDAT	WDT164	10/21/2004	Gale-Pole Switch 52 115 kV	80
58	TOT127	02/22/2005	Control 115 kV	62
WDAT	WDT315	07/31/2008	Casa Diablo 33 kV	40.7
909	TOT637	3/31/2012	Sandlot 220 kV (former Water Valley)	25
WDAT	WDT930	3/31/2012	Baroid 33 kV (out of Gale 115 kV)	20
WDAT	WDT931	3/31/2012	Remote 33 kV (out of Tortilla 115 kV)	20
WDAT	WDT946	3/31/2012	McGen 115 kV	0

Table H.2.5
Generation Project with Executed Agreements But In-Service Date After 2016 and All Other Generation Projects Assumed To Be Interconnected as Energy Only (Continued)

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Northern: Bulk				
84	TOT151	12/01/05	Whirlwind 220 kV	340
92	TOT154	10/01/12	Vincent 220 kV	570
94	TOT164	06/30/12	Highwind 220 kV	180
97	TOT165	06/30/12	Whirlwind 220 kV	160
119	TOT173	08/08/06	Windhub 220 kV	108[18]
153	TOT200	11/22/06	Whirlwind 220 kV	100
175	TOT215	05/30/08	Whirlwind 220 kV	650
494	TOT398	07/31/09	Windhub 230 kV	350
506	TOT411	07/31/09	Whirlwind 220 kV	300
513	TOT409	07/31/09	Whirlwind 220 kV	141
643AJ	TOT494	7/31/2010	Whirlwind 220 kV	100
643R	TOT497	7/31/2010	Whirlwind 220 kV	153
795	TOT544	3/31/2011	Whirlwind 220 kV	20
796	TOT545	3/31/2011	Whirlwind 220 kV	20
746	TOT573	3/31/2011	Whirlwind 220 kV	175
768	TOT585	3/31/2011	Antelope 220 kV	330
911	TOT645	3/31/2012	Pastoria 220 kV	50
922	TOT635	3/31/2012	Highwind 220 kV	291
926	TOT624	3/31/2012	Highwind 220 kV	550
927	TOT633	3/31/2012	Windhub 220 kV	45
Northern Area: North of Magunden				
WDAT	WDT390	10/19/2009	Vestal 66 kV	20
WDAT	WDT391	10/19/2009	Rector 66 kV	20
WDAT	WDT392	10/19/2009	Vestal 66 kV	20
WDAT	WDT394	10/19/2009	Vestal 66 kV	20
WDAT	WDT433	2/1/2010	Glennville-Vestal 66 kV	40
WDAT	WDT439	5/20/2010	Vestal 66 kV	20
WDAT	WDT603	6/30/2010	Vestal 66 kV	15
WDAT	WDT789	3/31/2011	Delano 12 kV	5
WDAT	WDT938	3/31/2012	Glennville-Vestal 66 kV	40
WDAT	WDT940	3/31/2012	Protein 66 kV	49

[18] This figure reflects the balance of the 516 MW Interconnection Requests.

Table H.2.5
Generation Project with Executed Agreements But In-Service Date After 2016 and All Other Generation Projects Assumed To Be Interconnected as Energy Only (Continued)

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Northern: Antelope-Bailey 66 kV System				
342	TOT307	07/31/08	Del Sur 66 kV	50
512	TOT410	07/31/09	Neenach 66 kV	26
WDAT	WDT361	08/20/09	Great Lakes 12 kV	5
WDAT	WDT404	11/30/09	Little Rock-Wilsona 66 kV	10
609	TOT459	02/01/10	Rosamond 66 kV	20
628	TOT471	02/01/10	Antelope-Cal Cement-Rosamond 66 kV Line	20
649C	TOT499	02/01/10	Antelope-Cal Cement-Rosamond 66 kV Line	20
650AA	TOT501	02/01/10	Antelope-Del Sur-Rosamond 66 kV Line	15
649B	TOT502	02/01/10	Antelope-Del Sur-Rosamond 66 kV Line	20
662	TOT521	02/01/10	Antelope 66 kV	20
658	TOT523	02/01/10	Antelope-Lancaster-Lanpri-Shuttle 66 kV Line	20
659	TOT524	02/01/10	Antelope 66 kV	20
661	TOT525	02/01/10	Antelope-Rosamond 66 kV Line	20
WDAT	WDT504	04/13/10	Del Sur 66/12 kV	10
WDAT	WDT527	04/26/10	Redman 66/12 kV	5
WDAT	WDT554	07/08/10	Little Rock 66/12 kV	5
WDAT	WDT625	09/07/10	Little Rock 66/12 kV	2
WDAT	WDT626	09/07/10	Little Rock 66/12 kV	2
670	TOT542	03/31/11	Antelope-Del Sur-Rosamond 66 kV Line	20
671	TOT543	03/31/11	Antelope-Lancaster-Lanpri-Shuttle 66 kV Line	20
738	TOT571	03/31/11	Oasis 66 kV	20
769	TOT586	03/31/11	Antelope-Del Sur-Rosamond 66 kV Line	20
778	TOT559	03/31/11	Antelope 66 kV	20
WDAT	WDT620	03/31/11	Piute 66/12 kV	2
WDAT	WDT621	03/31/11	Piute 66/12 kV	2
Northern: Saugus/Ventura				
WDAT	WDT560	05/20/2010	Elizabeth lake 12 kV	1
WDAT	WDT768	03/31/11	Santa Clara 66/16 kV	2
Northern: Windhub 66 kV System				
348	TOT313	05/30/08	Windhub 66 kV	40
WDAT	WDT1007	05/30/08	Windhub 66 kV	100
WDAT	WDT435	01/31/10*	Windhub 66 kV	20
521	TOT419	02/01/10	Corum-Goldtown 66 kV Line	20
522	TOT420	02/01/10	Corum-Goldtown-Rosamond 66 kV Line	20

* Date adjusted as a result of the FERC approved Generation Interconnection Procedure modifications

Table H.2.6
Transmission Upgrades Already Licensed but Expected to Be In-Service After 2016

System Upgrade	OD
Eastern Area	
Permanent West-of-Devers	2020
North of Lugo Area	
Third Lugo AA-Bank	2017
Northern Area	
Split Vincent 220 kV Bus	TBD

3. Inclusion of All Long-term Deliverability Network Upgrades

The GSI Study included a final scenario that added all of the long-term Deliverability Upgrades needed to provide for the requested Full Capacity Deliverability status level of service to all generation projects in queue including the Phase II project requests.

B. GSI Analysis: Study SCD Results

1. Existing System with the inclusion of projects in 2013/4

All bus locations where the inclusion of projects in 2013-4 increased the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in Appendix H Table H.3.1a (three-phase-to-ground) and Table H.3.1b (single-phase-to-ground). These values were used to determine which SCD mitigation needs to be placed into service by the end of 2013-4.

The 2012 GSI Study breaker evaluation identified the need for SCD mitigation at the following location:

(a) Lewis 220 kV

With the loop-in of the Del Amo - Ellis 230 kV line, short-circuit duties have been increased beyond the 50 kA capability of the six 220 kV circuit breakers.

To mitigate the overstressed breakers, SCE has upgraded the six 50 kA rated breakers with 63 kA rated breakers by adding TRV CAPS. The following lists the breakers that required mitigation:

- Pos. No.5 CB452, CB552 and 652
- Pos. No.5 CB562, CB662 and 462

(b) Mira Loma B (East) 220 kV

The 2013-4 Operational Study breaker evaluation identified the need for SCD mitigation at the Mira Loma 220 kV Substation East Bus Section. With the inclusion of new generation and transmission projects scheduled to be on-line by the end of 2013-4, short-circuit duties have been increased beyond the capabilities of five 220 kV 63 kA circuit breakers. These breakers are subject to a multiplier factor as defined by IEEE Standards. As a result, three-phase-to-ground duties identified in this operational study determined that the three-phase-to-ground duty on these five specific breakers was increased from an effective 57.2 kA to an effective 64.1 kA. To mitigate the overstressed breakers, an operational procedure will be implemented which will operate one existing 500/220 kV transformer bank on the Mira Loma East Bus Section as normally open and will only be closed when the other bank is unavailable. This mitigation will lower short-circuit duties to within existing circuit breaker limits.

2. Inclusion of projects in 2015

All bus locations where the inclusion of projects in 2015 increased the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in Appendix H Table H.3.2a (three-phase-to-ground) and Table H.3.2b (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service by the end of 2015.

(a) Devers 220 kV

The 2015 GSI Study breaker evaluation identified the need for SCD mitigation at the Devers 220 kV Substation. With the inclusion of new generation and transmission projects scheduled to be on-line by the end of 2015, short-circuit duties have been increased beyond the capabilities of four 220 kV circuit breakers. To mitigate the overstressed breakers, SCE has initiated a project to upgrade four 50 kA breakers to increase capability to 63 kA by October 2013. The following lists the breakers that require mitigation:

- Cap Bank CB42X2 (Upgrade)
- Cap Bank CB61X2 (Upgrade)
- Pos. No.10 CB 4102 (Upgrade) and CB 6102 (Upgrade)

3. Inclusion of projects in 2016

All bus locations where the inclusion of projects in 2016 increased the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in Appendix H Table H.3.3a (three-phase-to-ground) and Table H.3.3b (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service by the end of 2016.

The 2016 GSI Study breaker evaluation identified the need for SCD mitigation at the following locations:

(a) Serrano 220 kV

The 2016 Operational Study breaker evaluation identified the need for SCD mitigation at the Serrano 220 kV Substations. With the inclusion of new generation and transmission projects scheduled to be on-line by the end of 2016, short-circuit duties have been increased beyond the capabilities of all fourteen 220 kV 63 kA circuit breakers. These breakers are subject to a multiplier factor as defined by IEEE Standards. As a result, three-phase-to-ground duties identified in this operational study determined that the three-phase-to-ground duty on these specific breakers was increased from an effective 62.6 kA to an effective 63.5kA. Mitigation will need to be developed to address these overstressed circuit breakers.

(b) Vincent 220 kV

The 2016 Operational Study breaker evaluation identified the need for SCD mitigation at the Vincent 220 kV Substations. With the inclusion of new generation and transmission projects scheduled to be on-line by the end of 2016, short-circuit duties have been increased beyond the capabilities of all twenty-four 220 kV 63 kA circuit breakers. These breakers are subject to a multiplier factor as defined by IEEE Standards. As a result, three-phase-to-ground duties identified in this operational study determined that the three-phase-to-ground duty on these specific breakers was increased from an effective 62.6 kA to an effective 63.5kA. Mitigation will need to be developed to address these overstressed circuit breakers.

4. Inclusion of all Generation Projects Without an Executed Interconnection Agreement or With an Executed Agreement that Provides for an In-Service Date Beyond 2016 and Inclusion of CPUC Approved Transmission Upgrades Scheduled to be In-Service after 2016.

All bus locations where the inclusion of all remaining generation projects and inclusion of already licensed transmission projects that have a completion date after 2016 increased the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in Appendix H, as well as Table H.3.4a (three-phase-to-ground) and Table H.3.4b (single-phase-to-ground). These values were used to determine which incremental SCD mitigation will need to be placed into service to support all of these generation projects and completion of the already licensed transmission projects.

With the inclusion of all new remaining generation assumed to be interconnected as Energy Only but no upgrades modeled and the inclusion of all remaining licensed transmission projects scheduled to be on-line after 2016, short-circuit duties have been increased beyond the capabilities of all twenty-four 220 kV 63 kA circuit breakers at Vincent Substation. Mitigation will need to be developed to address these overstressed circuit breakers. The mitigation will involve reconfiguration of the 220 kV Line and Bus Arrangement at Vincent and splitting of the bus as a means to lower short-circuit duty. The actual need for this work is based on the number of projects that ultimately interconnect and the corresponding fault duty contributions. At this point in time, it is unknown when such mitigation will actually be required. Additional Operational Short-Circuit Duty studies will need to be performed as more projects near execution of an interconnection agreement to identify actual timing need for such short-circuit duty mitigation.

5. Inclusion of all Pending Deliverability Network Upgrades.

All bus locations where the inclusion of pending Deliverability Network Upgrades increased the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in Appendix H, as well as Table H.3.5a (three-phase-to-ground) and Table H.3.5b (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service to provide for the requested Full Capacity Deliverability service.

The GSI Study which layered all pending Deliverability Network Upgrades, either previously triggered but not yet in project licensing or triggered by the inclusion of QC5 Projects, identified five substation locations which required SCD mitigation. To mitigate the overstressed breakers, breaker upgrades or replacements will be required as Network Deliverability Upgrades are placed into service. Some of the overstressed breakers may undergo upgrade followed by replacement as short-circuit duties continue to rise.

The following provides a summary of each location requiring short-circuit duty mitigation:

(a) Vincent 500 kV – Replace/Upgrade the following seven 500kV circuit breakers with 63 kA:

- Pos. No.2 CB722
- Pos. No.5 CB752, CB852 and CB952
- Pos. No.6 CB762, 862, and CB962

(b) Etiwanda 230 kV – Mitigate 230 kV 63 kA circuit breakers:

- Pos. No.2 CB722
- Pos. No.5 CB752, CB852 and CB952
- Pos. No.6 CB762, 862, and CB962

(c) Antelope 66kV –

The Energy Only Operational Study breaker evaluation identified the need for SCD mitigation at the Antelope 66 kV Substations. With the inclusion of new generation and transmission projects scheduled to be on-line after 2016, short-circuit duties have been increased beyond the capabilities of all forty 66 kV 40 kA circuit breakers. These breakers are subject to a multiplier factor as defined by IEEE Standards. As a result, three-phase-to-ground duties identified in this operational study determined that the three-phase-to-ground duty on these specific breakers was increased from an effective 39.4 kA to an effective 44.1kA. Mitigation will need to be developed to address these overstressed circuit breakers.

(d) Windhub 66kV –

The Energy Only Operational Study breaker evaluation identified the need for SCD mitigation at the Windhub 66 kV Substations. With the inclusion of new generation and transmission projects scheduled to be on-line after 2016, short-circuit duties have been increased beyond the capabilities of all twenty 66 kV 40 kA circuit breakers. These breakers are subject to a multiplier factor as defined by IEEE Standards. As a result, three-phase-to-ground duties identified in this operational study determined that the three-phase-to-ground duty on these specific breakers was increased from an effective 30.9 kA to an effective 44.5kA. Mitigation will need to be developed to address these overstressed circuit breakers.

Actual timing of replacement of the above circuit breakers is closely tied with the in-servicing of additional Deliverability Network Upgrades. As a result, it is anticipated that these breakers will be scheduled concurrently with the corresponding Deliverability Network Upgrades that ultimately drives the timing need for the upgrade.

C. Additional SCD Discussion

The Phase II Study has shown significant increases in SLG short-circuit duty with the addition of numerous grounded interconnection transformers. For details, see Appendix H. It is strongly recommended that Phase II generation projects, to the extent possible, install transformers that limit each project's contribution to SLG SCD on the SCE system. This may be accomplished by installing transformers with delta-connected high side windings or with “impedance-grounded” wye-connected high side windings.

QC5 Phase II - Appendix H

Short Circuit Calculation Study Results

Table H. 1: Three – Phase-to-Ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	500	21.8	40.9	21.9	41.9	1
Lugo	500	21.6	46.9	21.6	47.1	0.2
Vincent	500	18.5	54.3	18.5	55.1	0.8
Windhub	500	25.7	28.7	26.7	30.5	1.8
Antelope	230	28.3	41.9	28.5	42.2	0.3
Eldorado_2	230	19.1	39.6	19	39.9	0.3
Highwind_230	230	22	18.3	24.8	21.9	3.6
Jasper	230	13.8	14.2	14	14.6	0.4
Lugo	230	25.7	44.6	25.5	44.7	0.1
Pastoria	230	13.4	30.8	13.5	31.2	0.4
Whirlwind	230	40.8	51.4	41.5	51.9	0.5
Whirlwind_2	230	40.8	51.4	41.5	51.9	0.5
Inyokern	115	5.7	12.7	5.3	13.1	0.4
Victor	115	18.5	24.6	18.5	24.7	0.1
Cal Cement	66	17.8	24.7	17.7	25.2	0.5
Rector	66	12.4	20.4	12	21.9	1.5
Vestal	66	12.3	22.2	11.2	26	3.8
Windhub66_A	66	51.6	34.8	52.6	35.8	1
Windhub66_B	66	51.6	34.8	52.6	35.8	1

Table H. 2: Single-Phase-to-Ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	500	17.4	34.6	17.3	35	0.4
Vincent	500	13.9	42.6	13.9	42.9	0.3
Antelope	230	28.6	46.4	28.7	46.7	0.3
El Casco	230	12.6	12.6	13.3	13.1	0.5
Eldorado_2	230	19.6	44.2	19.6	44.4	0.2
Ellis	230	15.5	39.5	15.3	40.5	1
Highwind_230	230	14.5	14.5	17.2	19.1	4.6
Jasper	230	9.8	10.2	9.8	10.3	0.1
Lugo	230	20.2	43.8	20.1	43.9	0.1
Pastoria	230	13.1	27.9	14.5	32.8	4.9
Whirlwind	230	30.8	59.1	31	59.5	0.4
Whirlwind_2	230	30.8	59.1	31	59.5	0.4
Windhub_A	230	46.1	35.6	43.6	38.5	2.9
Windhub_B	230	41.4	40.6	42.2	45.3	4.7
Inyokern	115	6.8	13.9	6.6	14.2	0.3
Cal Cement	66	9.1	15	9	15.1	0.1
Rector	66	13.4	21.3	13	22.6	1.3
Vestal	66	11.8	18.7	11.2	20.9	2.2
Windhub66_A	66	23.9	25.8	23.8	26.2	0.4
Windhub66_B	66	23.9	25.8	23.8	26.2	0.4

Queue Cluster 5 Phase II - Appendix K

Environmental, Permitting, and Licensing

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Appendix K
Environmental Evaluation, Permitting and Licensing

The Interconnection Customer may be required to complete environmental impact studies and obtain permits for the construction, operation, and maintenance of the Generating Facility and Interconnection Customer's Interconnection Facilities. Such activities would be the responsibility of the Interconnection Customer.

SCE may also be required to complete environmental studies and obtain permits/licenses for the construction, operation, and maintenance of its facilities, including its Interconnection Facilities and Upgrades. SCE implements procedures to ensure compliance with all applicable federal and state laws and regulations. Depending on the project, SCE's activities may be subject to the jurisdiction of several agencies, such as the California Public Utilities Commission (CPUC), California Department of Fish and Wildlife, U.S. Fish and Wildlife Service, State Water Resources Control Board or Regional Water Quality Control Board, U.S. Army Corps of Engineers, California Coastal Commission, Bureau of Land Management, and U.S. Forest Service.

As both SCE and the Interconnection Customer may be subject to similar requirements for performing environmental studies, it may be beneficial to combine portions of the environmental study processes. However, close coordination with SCE during the study process would be needed to ensure the final study/report/product meets SCE environmental requirements.

I. CPUC Licensing Requirements Pursuant to General Order 131-D

As an electric public utility, SCE is regulated by the California Public Utilities Commission (CPUC). The CPUC's General Order 131-D (GO 131-D) sets forth rules related to the planning and construction of electric generation, transmission, power, and distribution line facilities and substations located in California. The CPUC issued GO 131-D to be responsive to: the California Environmental Quality Act (CEQA); the need for public notice and the opportunity for affected parties to be heard by the Commission; and the obligations of the utilities to serve their customers in a timely and efficient manner.

Section III of GO 131-D addresses the need for CPUC authorization by the type of authorization needed for certain facilities constructed by electric public utilities. The requirements for a Certificate of Public Convenience and Necessity (CPCN) apply to the construction of major electric transmission line facilities designed for immediate or eventual operation at 200 kV or more (Section III.A). The requirements for a Permit to Construct (PTC) apply to the construction of electric power line facilities designed for immediate or eventual operation at a voltage between 50 kV and 200 kV, or new or upgraded substations with high side voltage equal to or exceeding 50 kV (Section III.B). Certain exemptions to PTC filing exist under GO 131-D.

Construction of facilities that require a CPCN or PTC cannot commence until the CPUC complies with CEQA requirements. An application for a CPCN or PTC must include a Proponent's Environmental Assessment (PEA) or equivalent information on the environmental impact of the project in accordance with the provisions of CEQA and the CPUC's Rules of Practice and Procedure for the CPUC's review (Section IX).

Generally, SCE takes approximately 18 to 24 months to assemble a CPCN or PTC application, the majority of which time is attributed to developing the PEA. The CPUC review of such applications may take an additional18 to 48 months depending on the specific issues.

For more details and a copy of GO 131-D, please go to:

http://www.cpuc.ca.gov/PUBLISHED/GENERAL_ORDER/589.htm

A. Certificate of Public Convenience and Necessity (CPCN)

Section III.A of GO 131-D requires electric public utilities to obtain a CPCN from the CPUC for the construction of major electric transmission line facilities that are designed for immediate or eventual operation at 200 kV or more except for the following: the replacement of existing power line facilities or supporting structures with equivalent facilities or structures, the minor relocation of existing power line facilities, the conversion of existing overhead lines to underground, or the placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built.

1. Expedited CPCN

There is no provision within GO 131-D that exempts the need for a CPCN for major electric transmission facilities that have undergone environmental review pursuant to CEQA as part of a larger project. Accordingly, if major electric line facilities have already undergone environmental review pursuant to CEQA by the lead agency that permitted the Generating Facility and the Interconnection Customer's Interconnection Facilities, SCE may consult with the CPUC on a case-by-case basis to determine whether the CPUC would allow for the project to proceed as exempt or allow SCE to proceed under an "expedited" CPCN application by attaching the final CEQA document in lieu of a PEA. Such an expedited CPCN typically may take from six to nine months for the CPUC to process.

B. Permit to Construct (PTC)

Section III.B of GO 131-D requires electric public utilities to obtain a PTC from the CPUC for the construction of electric power line facilities which are designed for immediate or eventual operation at any voltage between 50 kV and 200 kV, or new or upgraded substations with high side voltage equal to or exceeding 50 kV unless one of the listed exemptions under Section III.B.1 (exemptions a through h) applies. Note, though, that exemptions a through h shall not apply when any of the conditions specified in CEQA Guidelines §15300.2 regarding exceptions to categorical exemptions exist (Section III.B.2).

Appendix K
Environmental Evaluation, Permitting and Licensing

1. Exemption f to PTC

Exemption f of GO 131-D (Section III.B.1.f), in particular, exempts the need for a PTC for power lines or substations to be relocated or constructed which have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA document finds no significant unavoidable environmental impacts caused by the proposed line or substation.

SCE may be eligible to use exemption f after the Interconnection Customer's lead agency approves a final CEQA document that finds no significant unavoidable environmental impacts caused by SCE's proposed scope of work. To use exemption f, SCE would follow certain noticing requirements, including filing an informational advice letter with the CPUC, posting a notice on-site and off-site at the project location, advertising once a week for two weeks successively in a local newspaper at least 45 days prior to construction, and providing notice to the director for each county or city in which the project would be located and the executive director of the California Energy Commission. As part of an agreement with the CPUC Energy Division, SCE would informally provide a copy of the final CEQA document to the CPUC Energy Division for reference when the advice letter is pending before the CPUC.

The CPUC rules for advice letters consider an advice letter to be in effect on the 30th calendar day after the filing date. Typically, SCE may proceed with construction 45 days after noticing and posting unless a protest is filed and/or the CPUC suspends the advice letter. If a protest is filed with the CPUC, the protestant must address whether SCE has properly claimed the exemption. SCE would have five business days to respond to the protest, and the CPUC would typically take a minimum of 30 days to review the protest and SCE's response. The CPUC would either dismiss the protest or require SCE to file an application for a PTC. Note that SCE would have no control over the time it takes the CPUC to respond when issues arise.

2. Expedited PTC

For power lines or substations that have undergone environmental review pursuant to CEQA as part of a larger project but do not qualify for exemption f (final CEQA document finds significant unavoidable environmental impacts caused by the proposed line or substation), SCE may be able to file for an expedited PTC, which typically takes the CPUC approximately six to nine months to process.

If construction does not qualify for an expedited PTC or an exemption to a PTC, SCE may need to seek approval from the CPUC, taking as much as 18 months or more as the CPUC would need to conduct its own environmental review pursuant to CEQA by preparing a PEA and the CPUC issuing an Initial Study and Negative Declaration or Environmental Impact Report.

C. Projects on Federal Land

If an Interconnection Customer is seeking approvals for the Generating Facility and Interconnection Customer's Interconnection Facilities from only a federal agency and not from a state agency, the federal lead agency would generally prepare an environmental document pursuant to the National Environmental Policy Act (NEPA). Note that the provisions of GO 131-D do not allow for the use of exemption f, expedited PTC, or expedited CPCN when the environmental review is conducted only pursuant to NEPA and not to CEQA requirements. SCE may consult with the CPUC on a case-by-case basis to determine whether the CPUC would allow for the project to proceed exempt or would expedite the PTC/CPCN application process if SCE were to submit the final NEPA document in lieu of a PEA.

D. Projects Not Subject to CPUC GO 131-D Permitting

Section III.C of GO 131-D does not require issuance of a CPCN or PTC from the CPUC for the construction of electric distribution (under 50 kV) line facilities, or substations with a high side voltage under 50 kV, or substation modification projects which increase the voltage of an existing substation to the voltage for which the substation has been previously rated within the existing substation boundaries. Note, though, that the construction of facilities under 50 kV may affect and require work on facilities over 50 kV.

In cases where permits are not required from the CPUC, SCE may be required to obtain permits from other regulatory agencies. For additional information, please see section III below (Permitting Requirements by Resource Agencies).

II. CPUC Approval Requirements Pursuant Section 851

Since SCE is subject to the jurisdiction of the CPUC, it must also comply with Public Utilities Code Section 851. Among other requirements, this code provision requires SCE to obtain CPUC approval of leases and licenses to use SCE property, including rights-of-way granted to third parties for Interconnection Facilities. Obtaining CPUC approval for a Section 851 application can take several months, and requires compliance with CEQA. SCE recommends that Section 851 issues be identified as early as possible so that the necessary application can be prepared and processed. As with GO 131-D compliance, SCE recommends that the project proponent include any facilities that may be affected by Section 851 in the lead agency's CEQA review so that the CPUC does not need to undertake additional CEQA review in connection with its Section 851 approval.

III. Permitting Requirements by Resource Agencies

For both projects that are subject to and projects that are not subject to CPUC permitting, SCE must ensure that requirements of all applicable environmental laws and regulations are addressed, necessary environmental surveys and studies are performed, and all required state and federal environmental permits are applied for and secured from various resource agencies before commencement of construction activities. Resource agencies such as California Department of Fish and Wildlife, U.S. Fish and Wildlife Service, State Water Resources Control Board or Regional Water Quality Control Board, U.S. Army Corps of Engineers, California Coastal Commission, and U.S. Forest Service are required to comply with CEQA or NEPA, as applicable, when issuing permits. Therefore, in order to secure permits from such agencies, SCE's work may require environmental surveys/studies/reports even if no license is required from the CPUC.

Although the necessity for environmental permits is oftentimes unknown during the initial stages of project development, it is recommended that the Interconnection Customer and SCE combine portions of their environmental study processes.

A. CEQA/NEPA Documentation

If the Interconnection Customer incorporates SCE's scope of work into its environmental study reports, it is recommended for the Interconnection Customer to closely coordinate with SCE during the environmental review process to ensure that SCE's scope of work is being adequately described, and to ensure that environmental studies are being performed to industry standard. If the resulting environmental documents do not adequately describe SCE's scope of work or do not adequately analyze the environmental impacts caused by SCE's scope of work, as determined by SCE, SCE and/or the permitting agencies may not be able to rely on such documents and additional environmental documents may need to be prepared, resulting in delays to the project schedule.

B. Permit Applications

Applications for permits from resource agencies (i.e., Streambed Alteration Agreements or Incidental Take Permits) shall be submitted by SCE for all SCE project components. Therefore, SCE (not the Interconnection Customer) shall be the permit holder for all such permits. It is SCE's experience that securing such permits may take from six to 12 months, depending on the permit type, from the time complete permit applications are submitted by SCE to the resource agencies for agencies to process. More complex permitting, such as Endangered Species Act Section 10 Habitat Conservation Plans and Bald and Golden Eagle Protection Act permitting, are more laborious and may require more than a year—in some cases, multiple years—to perform surveys and prepare plans to adequately address agency requirements.

IV. Recommendations

For the reasons stated above, it is recommended that the Interconnection Customer identity and include all of SCE's Interconnection Facilities, Distribution Upgrades, and Plan of Service Network Upgrades (including facilities to be constructed by others and deeded to SCE) in the Interconnection Customer's environmental study reports submitted to the lead agency permitting the Generating Facility and the Interconnection Customer's Interconnection Facilities (e.g., California Energy Commission, Bureau of Land Management, city, county, or other applicable local, state or federal permitting agency).

It is also recommended that such lead agency(ies) review the potential environmental impacts associated with SCE's scope of work in any environmental document prepared. Doing so may enable SCE to proceed "exempt" from CPUC permitting requirements or under an "expedited" PTC or CPCN. SCE may also be required to obtain other authorizations for its Interconnection Facilities and Upgrades. However, depending on certain circumstances, the CPUC may still require SCE to undergo a standard PTC or CPCN for the facilities associated with the Interconnection Customer's Generating Facility. Hence, SCE's facilities needed for the project interconnection could require an additional two years, or more, to license and permit.